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The Use of Continuous Emissions Monitoring To Track, Record, and Report Criteria Pollutant Emissions

A Summary of Current Technologies

by

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On 15 November 1990, President George Bush signed into law the Clean Air Act Amendments, which distinguish between: (1) "air toxics" and (2) "criteria pollutants." Central energy plants (CEPs) like those found on military installations in the continental United States generate certain levels of this second class of pollutants and, by law, must be monitored. Most installations in the continental United States are actually regulated for pollution emissions by their State governments, which, in turn, must meet Federal regulations. Meeting the attendant hierarchy of requirements depends wholly on a process of accurate monitoring, recordkeeping, and reporting of sulphur dioxide (SO_2), nitrogen oxide (NO_x), and carbon dioxide (CO_2) emissions.

Installations required to install continuous emissions monitoring (CEM) equipment to meet State and Federal requirements may select from an array of technologies to monitor a spectrum of emissions. This work outlined available CEM technologies to help Army and Air Force installation design engineers and energy plant personnel select appropriate technologies to track, record, and report emissions of criteria pollutants according to State and Federal Environmental Protection Agency (EPA) requirements.

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Foreword

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Distribution

1 Introduction

Background

On 15 November 1990, President George Bush signed into law the Clean Air Act Amendments (Public Law 101-549, hereafter simply referred to as the "CAAA"), which distinguish between two types of pollutants: (1) hazardous air pollutants (HAPs, or "air toxics"), and (2) criteria pollutants. Air toxics comprise a long list of pollutants that can cause serious illness or death, but which are usually industry-specific. (Title III of the Clean Air Act Amendments lists these pollutants.) Criteria pollutants, on the other hand, are fairly common, come from diverse sources, and may be reasonably anticipated to endanger public health or welfare. Central Energy Plants (CEPs) like those found on Army/Air Force installations in the continental United States generate certain levels of this second class of pollutants and, by law, must be monitored. The six criteria pollutants are:

- ozone
- lead
- particulates (PM_{10})
- sulfur dioxide (SO_2)
- nitrogen dioxide (NO_2)
- carbon monoxide (CO).

Since the CAAA was adopted, changes have been written into the U.S. Code (U.S.C.) allowing the Federal Government to institute appropriate regulations (40 CFR, "Protection of the Environment"). One notable change is that, for the purposes of continuous emissions monitoring (CEM), a "stationary source" is defined as any governmental, commercial, or industrial structure, installation, plant, building or facility that has the potential to emit any regulated air pollutant. This new provision (from 40 CFR Part 72), which is currently in effect at the time of this writing, significantly extends the definition of a stationary source from previous Federal legislation, which was passed into law before CAAA 1990.

State or local governments regulate military (i.e., Army or Air Force) installations in the continental United States (and in U.S. territories) for air pollution emissions. However, the States themselves must meet Federal regulations, and under extreme

circumstances, military installations may be directly overseen by the U.S. Environmental Protection Agency [USEPA]—a Federal regulating agency.

The USEPA requires State regulating agencies to put together State Implementation Plans (SIPs), which show how each State plans to comply with Federal regulations. SIPs are subject to approval by the USEPA, and, if the States submit their implementation plans on time, the USEPA allows the States to operate as if the plan were approved until the USEPA has had time to review and approve (or disapprove) the plan. In fact, many States' regulations are more stringent than Federal requirements. However, if the USEPA does not approve the State implementation plan, then Federal regulations apply to sources within that State until approval of the State implementation plan.

In some cases, the situation can become more complicated. All States have approved SIPs in which some parts may not have been approved or updated. Each USEPA regulation must be read carefully because some regulations are effective even before inclusion in an SIP (while other regulations become effective only after they have been approved in the SIP). Moreover, States also use new source performance standards (NSPSs) or other USEPA performance documents to develop their SIPs and regulations. NSPSs will most likely be effective before inclusion in a SIP.

Most States or local regulatory agencies (or the USEPA in cases in which the SIP has not been approved) require each source or installation to submit permits to the regulating agency and then to comply with that permit. The permit is a legal document that states which laws are applicable to the source and the levels at which the specified source is allowed to emit pollutants. States are required to update and obtain approval from the USEPA for the SIPs every 10 years. However, many States require sources to update their permits on a different time line. Meeting this hierarchy of requirements depends wholly on a process of accurate monitoring, recordkeeping, and reporting of SO₂, NO_x, CO, carbon dioxide (CO₂), and HAP emissions.

New operating permit regulations were legislated under the Title V of the Clean Air Act Amendments of 1990. The documentation required for an operating permit is long and involved—regardless of whether an SIP is in place. The equipment in place will affect the agreement, i.e., how often the State will require reporting.

The USEPA has delayed its decision on requiring CEMs for industrial-size boilers because the technology is not yet mature, but specific NSPSs or regulations by the USEPA, State, or local regulatory agencies may require CEMs. It is anticipated that the major requirement outside the acid rain program will come from the USEPA proposed rule "Compliance Assurance Monitoring" (CAM). In fact, continuous

emissions monitoring is a rapidly developing, computer-based technology. Some CEM manufacturers are selling technology that reflects the current state in the development of their proprietary products; such equipment is likely to become obsolete as more advanced equipment is brought on the market. It is anticipated that, in the next 5 years (the USEPA's target date for phasing in CEM technology), the field will be much more mature. Research should allow for more innovative use of laboratory equipment, and for all needed sensing equipment to feed into a single computer.

Therefore, it is recommended that military installations adopt a "wait and see" attitude, that they *not* install equipment that is not yet required, especially considering that such equipment will be expensive to acquire and difficult (in certain cases, impossible) to maintain. If regulations can be met some other way than by installing CEM equipment, they should be. Installations should do cost analysis of yearly tests, and monthly or semi-annual reports, which may indicate significant potential savings over the purchase of CEM equipment.

Each permit must meet specific standards, but, to a point, how those standards are met can be negotiated with the State regulating agency. Negotiation with State regulators is important. Most CEM regulations are written for Resource Recovery Facilities, Utilities, Cogeneration Plants, and Medical Waste Incinerators. Since some military installations are located in air pollution attainment areas and not near large population centers, they may not be required to install CEMs. An early consultation with State regulators can determine whether installations can use yearly testing and fuel reports as a basis for compliance. In some cases, this will be cheaper than the yearly cost of maintaining the CEM system.

If an installation is required to install a CEM system, the purchase contract must be set up with great care. An installation should ensure that its contracting officer completely understands the legal ramifications of using CEM systems. If the equipment is inaccurate and incorrect readings are reported to the State, the repercussions could be both expensive and long lasting. It may take many expensive tests to ensure that the problem is corrected, and State or local regulatory agencies may scrutinize the facility more closely after a mistake has been discovered.

For example, the USEPA allows some CEMs to be accurate within a tolerance of ± 20 percent to accommodate for the fact that some sensors are known to degrade with time. A previous USACERL study (Northrup 1995) documented one case in which a CEM manufacturer convinced a contracting officer to accept equipment that was off specified limits by 18 percent when new. Technically, the equipment fell within legal limits, but functionally, the equipment could have been out of compliance soon after acceptance.

Some States (e.g., Connecticut) have CEM Acceptance and Quality Assurance/Quality Control test programs that may help installations ensure procurement of good working equipment by specifying certain passing test results in the contract scope of work (cf. *Continuous Emission Monitoring Technology for the 90s* [Air & Waste Management Association, 1992], p 55). For example, some of the following acceptance test could be included in the contract:

1. A 30-day operational trial period (OTP)
2. Calibration drift test in accordance with 40 CFR 60, Appendix B
3. A four-point linearity testing (a Connecticut CEM Guideline)
4. Relative accuracy test in accordance with 40 CFR 60, Appendix B.

If the contract officer understands these technical issues before the contract is let, clauses can be written into the contract to ensure that the manufacturer delivers a product that meets the installations needs and legal responsibilities. If a proper contract cannot be specified, the community commander should be informed, since the commander is both criminally and civilly responsible for air pollution violations, with penalties up to \$25,000 per day.

Installations required to install CEM equipment to meet State and Federal requirements may select from an array of technologies to monitor a spectrum of emissions. The following summary of available CEM technologies can help installation personnel choose appropriate CEM equipment to maintain compliance with current State and Federal emissions regulations.

Objective

The objective of this work was to outline available CEM technologies to help Army and Air Force installation design engineers and energy plant personnel select appropriate technologies for tracking, recording, and reporting emissions of criteria pollutants according to State and Federal EPA requirements.

Approach

Using CEM technologies to meet State or Federal emissions requirements implies a dynamic collaboration of several principal elements: (1) an appropriately chosen CEM technology, (2) a regular program of tracking, recordkeeping, and reporting, and

(3) careful review of the requirements of the specific State or Federal regulating agency. A literature search was done to investigate currently available CEM technologies, and to outline applicable State and Federal requirements. The search revealed a complete summary of emissions regulations and required sampling, recordkeeping, and reporting procedures by the Electric Power Research Institute (EPRI), which has been reprinted (with permission) as Appendixes to this report.

2 Continuous Emissions Monitoring Technologies

Purpose of CEM Equipment

Before emission controls were required by law, they were most commonly installed as “add-ons” to the then-current technology. Many monitors were first installed only to enhance the efficiency of equipment maintenance and to provide a framework to develop a self-correcting system. Moreover, most control equipment (such as baghouses and spray dryers) is complicated and expensive. Consequently, the results of these early installations were sometimes hard to quantify. It was soon found that monitoring was required frequently, if not continuously, if it is to provide measurements accurate enough to confirm emission reductions. Only later, as new regulations were promulgated, was emissions monitoring technology written into the law as a requirement.

Procurement

The procurement of CEM equipment is a challenging task. CEM technology is changing and improving as rapidly as any other computer technology. It is important to bear in mind that, over the life cycle of CEM equipment, operation and maintenance costs will be many times higher than the initial purchase and installation costs. This fact complicates the design and purchase of new equipment since the life-cycle cost-effectiveness is determined by many factors beyond initial purchase and installation price.

In some cases, a staff expert may be able to assemble a system from components, but more commonly, an installation will try to purchase a complete system. Since the cost of a complete CEM system is over the limit of sole source contracts, the contract will be given to the lowest bidder unless the designer is very specific. This means that the engineering staff must construct the contract scope of work in as much detail as possible to guarantee that the contractor deliver good quality equipment that fills the installation's needs.

At this stage, it is easy to avoid a few common pitfalls. For example, the repair technician should be a part of the design team *during system specification and design*,

before the system is actually installed. This "nuts and bolts" input will help avert design flaws that will make the equipment hard to service.

For example, a three-phase connection should have a quick release plug if it can be wired wrong. In fact, if there is a 50/50 chance of doing the connection wrong each time that it is disconnected, one should assume that it will be done wrong some time. Such simple features incorporated early, during system specification and design, can help avoid many lengthy and expensive diagnostic and repair processes.

The repair technician input will also be important in specifying a good preventive maintenance schedule—a vital factor in avoiding breakdowns. This is especially important with CEM systems, which must be available no less than 90 percent of the time.

The design team should work from the system specifications of the installed boiler. State and local regulations should be procured from the proper agencies. The Federal requirements included in Appendix A to this report were originally published in 1993. As such, they have two limitations: (1) they, and modifications found in 40 CFR would be effective for States that have not finished a State Implementation Plan (SIP) by the date that the CEM work begins, and (2) if there is a SIP for the State of the military installation where the CEM is to be installed, those State regulations must be followed.

The design team should not depend on the manufacturer's advertising copy. CEM systems are complicated tools. The range of possible errors and the possibility of making those errors are both quite large. Manufacturer's literature is meant to highlight a system's capabilities and minimize its limitations; advertising product information will not necessarily find the best match between the buyer's needs and the vendor's system capabilities.

Appendix A to this report lists Part 75 requirements for comparison with other regulations. It is important to review these requirements before designing a new CEM or preparing a Title V permit application. Appendix B, "Status of State Title V Operating Permit Programs," lists information on Title V operating permit programs by State. This allows a quick comparison of programs between States, but is *not* intended to substitute for a copy of State regulation. In Montana, for instance, each Federal, State and local regulation that may apply to air regulation and permit must be reviewed and a statement must be made regarding the applicability of the regula-

tion at the permit site. This can and should be included in the permit as a litigation shield. Since most military lawyers do not have environmental litigation in their background, it is advisable for the installation environmentalist to have this kind of information available when starting to prepare the Title V.

The next task is to determine what the new regulations mean to those who work in energy or process plants. The relevant chapter for CEM for utilities can be found in 40 CFR part 75, entitled "Continuous Emissions Monitoring." The regulation is organized into seven general parts:

- Subpart a General Information
- Subpart B Monitoring Provisions
- Subpart C Operation and Maintenance Requirements
- Subpart D Missing Data Substitution Procedures
- Subpart E Alternative Monitoring Systems
- Subpart F Record Keeping Requirements
- Subpart G Reporting Requirements.

Several appendixes contain procedures for specifications, testing, quality assurance, quality control, missing data estimation, conversion, emissions estimation, and traceability protocols.

This regulation establishes the following requirements: monitoring, recordkeeping and reporting of SO₂, NO_x and CO₂ emissions, volumetric flow rates, opacity data (if SO₂ concentration measurements are made on a dry basis) and O₂ concentration (if CO₂ concentration is determined using part 75 Appendix F procedures). The three major emissions concerns of this regulation are SO₂, NO_x, and opacity. However, future regulations may also require measurement of HAPs (e.g., mercury) and volatile organic compounds (VOCs).

System Components

A CEM system is defined by Federal regulations as the equipment required by 40 CFR part 64, 40 CFR part 70, 40 CFR part 75, or a CAM rule to sample, analyze, measure, and provide a permanent record of emissions in lb/hr for SO₂ and in million Btu for NO_x. Readings for the permanent record must be taken at intervals of 15 minutes. Some possible components of a CEM system are:

- a sampling probe
- an SO₂ monitor

- a NO_x monitor
- a CO₂ or O₂ monitor
- a flow monitor
- an opacity monitor
- a moisture monitor.

Some of these components may be optional (e.g., the moisture monitor), depending on the type of sampling system in use. Moisture monitors, for example, are necessary for use with SO₂-flow extractive CEM systems so that SO₂ can be calculated in lb/hr. A brief description of each component follows; more detailed information can be found in Appendixes C and D.

Sampling Systems

The three main types of sampling techniques are: (1) dilution-extractive, (2) extractive (sampling without the dilution of the sample gas), and (3) in-situ. Each system has its own advantages and disadvantages.

Dilution-Extractive Systems

Dilution-extractive systems dilute the sample gas taken from the exhaust stream and dilute it with large quantities of conditioned air to eliminate condensation problems in the CEM system. This method allows for analysis of the sample at or near ambient concentration ranges. A specially designed probe is used to collect and dilute the sample of gas from the stack. Dilution ratios tend to range from 50:1 to 250:1 and must ensure that no condensation develops in the sample line at the lowest possible ambient temperature. This system is relatively simple and inexpensive to maintain because the main transport system of the sample gas has no moving parts and uses monitors that would be familiar to personnel currently working with ambient air monitors.

Drawbacks of the dilution-extractive systems are that:

1. To maintain stable dilution ratios, stable sampling temperatures need to be maintained.
2. The probes may get clogged in the presence of sticky particulate matter.
3. They require the use of CO₂ monitors that are more difficult to maintain than O₂ monitors that are used with other systems.

Extractive Systems

Extractive systems remove effluent gas samples from the exhaust stack and have a sample conditioning system that removes particulate matter and moisture from the sample prior to being analyzed. They are comprised of several subsystems: (1) the effluent/CEM system interface, which is a rigid probe that contains coarse filtration media to remove particulate matter from the gas sample; (2) the transport system, composed of transport lines (usually heated to prevent condensation) and a pump or similar mechanism to move the sample gas; and (3) the sample conditioning system, which provides a clean, dry interference-free gas sample to the analyzers to be tested. Extremely accurate data can be obtained if a good maintenance program is followed and this type of system can be located remotely from the stack, making access for maintenance easier. However, this system is highly susceptible to corrosion and failures are often difficult to track down.

In-Situ Systems

In-situ systems are located directly in the stack and do not require sampling, since all the analysis is performed in the stack. Two methods are used: (1) "across-stack," which analyzes gas passing through a specific line-of-sight of the monitor, and (2) "through-stack," in which an instrument analyzes the effluent at a specific point or along a short path in the stack.

Drawbacks are that this type of system is exposed to ambient dust, severe weather conditions, and effluent gas that is often wet and corrosive. Maintenance for these systems is high. Particulate matter and water droplets cause interference; optical systems are subject to condensation and particulate build-up and may also not achieve sufficiently high data capture to comply with 40 CFR part 75.

Gaseous Monitors

Gaseous monitors can be grouped according to the constituents of the flue gas that they monitor. The specific technologies will not be discussed in detail. Details can be found in Appendixes C and D to this report.

SO₂ Monitors

There are three commonly used ways to measure concentrations of SO₂ in the effluent:

1. *UV Spectrophotometric Monitors.* UV spectrophotometric monitors are based in the UV and second-derivative UV technologies. They are available for in-situ as well as extractive CEM systems. They have been proven to be reliable and many of the electronic components have been improved in the last 5 years.
2. *Fluorescence Monitors.* Pulsed fluorescence SO_2 monitors were originally manufactured for ambient air monitoring, so they may be familiar to installation personnel who have worked with air monitoring in the past. They operate well at low concentrations, and are often used in dilution-extractive systems. Advances in optical filtering have substantially reduced problems with quenching, but use of a calibration gas that contains similar concentrations of O_2 and CO_2 is recommended when this type of monitor is used in extractive systems.
3. *Flame Photometric Analyzers.* Flame photometric analyzers detect the light emitted at a wavelength of 394 nm from combustion of sulfur compounds in a hydrogen rich flame. They are more accurate than UV monitors at low concentrations and do not rely on a light source with a short life span. The main disadvantage is that hydrogen gas is required for the flame source and the safety and liability concerns associated with handling hydrogen gas cylinders need to be considered.

NOx Monitors

NOx Monitors use either chemiluminescence or UV spectrophotometric technologies.

Chemiluminescence. Chemiluminescence monitors have been used at utility sites for years and have a proven performance record. Some are now available with a microprocessor that enables the operator to check certain parameters and perform calibrations and many diagnostic functions automatically. In cases where ammonia interference is a possibility, the use of catalytic converters is necessary.

Drawbacks of catalytic converters are that they require periodic replacement, and that the capillary tubing used to regulate sample by-pass and ozone flow rates can become plugged without proper gas conditioning. These monitors incorporate a high vacuum sample chamber to minimize quenching.

Spectrophotometric. UV spectrophotometric monitors have also been used for years in utility applications. They require sample filtering to remove particulate matter and sample conditioning of heated sample cells to maintain the sample gas above dew point. They contain few moving parts and maintenance is relatively easy compared to that of chemiluminescence monitors.

CO₂ Monitors

CO₂ monitors all use infrared (IR) based technologies to detect CO₂. They use either nondispersive infrared (NDIR) or gas filter correlation (GFC) monitors for the most part. NDIR monitors use a dual-beam optical system to measure how much pollutant is present in a gas sample. Infrared radiation is passed through the sample gas and a reference cell. The difference in intensities of the radiation once it has passed through the cells is used to calculate the concentration of the pollutant. GFC passes a beam of light through a sample of the gas to be analyzed and a reference gas filter consisting of pure target gas. The difference in intensities is then used to calculate the concentration of the target gas in the sample. A more detailed discussion of these technologies is located in Appendixes C and D to this report.

CO₂ monitors are considered to be less reliable than O₂ monitors, except when using a dilution-extractive system since a CO₂ monitor must be used then. They are also subject to moisture and particulate matter interference.

O₂ Monitors

O₂ Monitors generally use magnetodynamic and magnetopneumatic monitors as well as paramagnetic monitors. Magnetodynamic monitors use the paramagnetic property of oxygen molecules to measure content of oxygen in a sample gas. A dumbbell-shaped platinum ribbon is used in a magnetic field. When sample oxygen is added, the magnet attracts the oxygen molecules, changing the magnetic field line around the platinum. The platinum begins to swing and this motion is detected by an optical system. Current supplied to a coil wrapped around the dumbbell returns it to position. The amount of power necessary to do this is proportional to the concentration of O₂. The magnetopneumatic monitors use the magnetic properties of O₂ molecules in a similar fashion, but sense differences in pressure between two cells of gas. This pressure difference is then used to calculate the concentration of O₂. Several other technologies are now being marketed, but these are relatively new and are not yet widely used.

Flow Monitors measure velocity and volumetric flow using ultrasonic pulse detection, differential pressure, or thermal detection (convective cooling). Proper flow monitor installation is critical for ensuring accurate data as well as regulatory compliance.

Ultrasonic flow monitors measure flow rate by transmitting ultrasonic pulses across the stack in both directions. The tone pulses are accelerated or retarded due to the gas velocity in the stack. The time required for the pulse to cross the stack with and against the stack flow is a function of the sound velocity and the effluent velocity. The flow rate can be calculated based on the difference in the times required to cross the

sack in both directions. The angle at which the pulse crosses the track must be at least 10 degrees, but angles of 40 to 70 degrees tend to be most accurate. Advantages are that the monitor reading is an average across the stack and the transducers are not exposed to the flue gas, thereby lowering corrosion problems. Some disadvantages are that the transducers must be mounted at different heights, which may increase capital costs and make maintenance more difficult.

Differential Pressure Flow Monitors

There are three different differential pressure monitors available: (1) annubars, (2) S-type pitot tubes, and (3) Fechheimer dual-manifold, pitot tubes.

The annubar is a multipoint, dual-chambered probe that averages multiple in-line sample points across the stack diameter. The interior of the probe consists of tubes within a tube. The inner tubes consist of the impact differential pressure chamber and the wake differential pressure chamber. The pressure registered at the flow transmitter is the average across the stack.

The S-type pitot tube consists of a probe made up of two opposing open faces perpendicular to the traverse axis. A side view of the probe resembles two stacked tubes with the ends tapered away from one another and the openings planed parallel to the horizontal axis. Several probes are required for multipoint monitoring. The averaging is performed in a pitot manifold and the averaged pressures are registered by the flow transmitter.

The Fechheimer pitot probe consists of flow sensors mounted on two multipoint averaging manifolds. The probe design consists of two manifolds welded together with a truss plate. The truss maintains a distance between the manifolds in a plane perpendicular to the flow and the stack wall. One manifold averages multiple points of impact pressure and the other averages multiple points of wake pressure. The impact and wake pressure averages are registered by the flow transmitter.

All systems include an electronic flow-indicating transmitter that receives pressure and temperature signals from the stack, calculates the exhaust gas flow rate, and, as an option, automatically performs electronic drift checks and system purging. Corrosion can be a serious problem in these systems. Pressure differential systems typically have sensors that can be easily replaced at minimal cost. Pitot tube systems are adaptable for multipoint analysis, but become very complicated with multiple tubes. Annubar probes tend to be less susceptible to turbulent flow problems. Differential pressure systems may work best in extremely wet effluent streams.

Thermal Flow Monitors

Thermal flow monitors measure the electric power required to maintain a constant temperature of approximately 75 to 100 °F above the exhaust gas temp in a flow sensor. The power required is proportional to the convective cooling effect of the exhaust gas. Monitors are available for both single- and multipoint analysis and non-sensing components of the system can be constructed from various corrosion-resistant materials. One advantage is that they can be used to produce measurements from the same "equal-area" sampling configuration required by the EPA. As with pressure differential probes, build-up and corrosion can be serious problems at some locations. They typically function better than other flow monitors under very low flow conditions, but should not be used where condensation may occur.

Moisture Monitors

Moisture may be measured either directly or indirectly. The direct methods use NDIR and polarography and operate in the same manner as NDIR and polarographic monitors for pollutants. Indirect methods measure the concentrations of gaseous compound in the sample gas on a wet basis and then on a dry basis. The percent difference in concentration from the wet and dry measurements is used to calculate the gas moisture content. The indirect method is more convenient (when using extractive CEM system), reliable and accurate, but it could be more expensive to buy and maintain.

Data Acquisition Systems (DAS)

The data acquisition system is necessary to provide a continuous and permanent record of all CEM system emission data, quality assurance and quality control audit results, and required process information. It must also be capable of calculating the emissions, generating necessary reports, and tracking system status. The emission measurements and information must be stored in a manner that makes transmittal easy through electronic media in a flat ASCII file. The DAS system must be capable of logging data as required by 40 CFR part 75 and the USEPA's electronic data reporting procedures. Since emissions laws tend to change often, the system must be flexible. Short term data storage can be provided using a programmable logic controller, but longer term information storage requires the use of a personal PC or backup on a tape drive.

A COM system is defined by Federal regulations as the equipment required to sample, measure, analyze and provide a permanent record of opacity or light transmittance.

Opacity readings must be taken and recorded at 6-minute intervals. The components of a COM are an opacity monitor and a data acquisition system similar to that of a CEM system.

Opacity Monitors

Transmissometers operate by passing visible light through the exhaust gas and measuring the percent obscuration caused by particulate matter in the effluent. They are located in-situ in the exhaust stacks or ducts. There are two basic types single- and double-pass systems. The single-pass system shines a light across the stack and the light on the other side is measured. In double-pass systems, the light beam is projected across the stack and reflected back to be measured. Both systems use an air purge system at the transmissometer/stack interface to prevent particulate or moisture from collecting on the optics and causing erroneously high readings. Double-pass monitors are more reliable and easy to calibrate, but they are also more expensive.

It should be noted that the regulations in Part 75 are in no way meant to modify or supersede any other existing regulations. Facilities must satisfy all monitoring requirements that are applicable. It is required that the system and all components meet specific hourly operating requirements (EPRI 1993). The EPA evaluates specific equipment and the methods used by that equipment for CEM, and announces its findings in the Federal Register. Appendix E to this report lists equipment approved for monitoring industrial ambient air as of December 1994 (*Air Pollution Control* 1994).

After the system is installed, all concerned regulatory agencies must certify the system. At the same time, a monitoring plan must also be included (in accordance with 40 CFR Part 75). The notification to the EPA includes the anticipated dates and protocol for testing the system. After testing, an application for certifications must be sent to the EPA within 30 days. The facility must also put together a Quality Assurance Manual. It must contain written details on the quality assurance and quality control activities that are performed to comply with all applicable regulations. Obviously, these activities require substantial amounts of time and effort. Wherever possible, these tasks should be assigned to personnel who have the requisite skills. If the skills do not exist at the facility, resources should be allocated to enable staff to acquire the appropriate training.

System Operation

To ensure routine operation with minimal downtime and required data availability, personnel responsibilities must be clearly designated. There is no hard, fast method of doing this. Since every facility can be different, it is up to the individual facility to determine the structure that best works for them. Under 40 CFR Part 75, the owner, operator, or designated representative will submit reports, notifications, petitions, or certification applications. As far as maintenance activities are concerned, it is up to the individual facility to determine the most appropriate way to perform maintenance. It should be remembered that training of personnel may be required to meet new responsibilities. Another possibility may be to hire outside contractors to handle maintenance activities. Again, it is for the individual facility to determine.

With the increase of local area network (LAN) systems at military installations, it is conceivable that the information gathered by a CEM system could be sent directly to a pollution management system. This program could then automatically generate the necessary logs and reports for compliance with environmental regulations. If this were implemented, the man-hours involved with compliance requirements would be greatly reduced. At present, work is underway on the DOD Air Quality Management Information System (DAQMIS). There are tentative plans to field those programs to all of DOD in the future. Although the systems do not currently have the capabilities to have direct input from a CEM system, modifications can be made to make it possible.

Predictive Emission Modeling (PEM) as a Substitute for CEMs.

The problems with the CEM technology have not been lost on the industries that have had to use them. The USEPA's group 1, which includes large Electrical Companies, has complained vehemently that the CEM technology was not mature enough for the government to require it as the "best available technology." It is only natural that some entrepreneurs would look for a better alternative. Using the operational parameters and the rugged sensors already in the boiler house, software has been developed to model the process and, after tests have been run to define the algorithms for a particular process, to predict emissions.* The speed of modern personal computers (PCS) allows the formula to be reconfigured "on the fly" for available parameters. The resulting software not only outputs emissions levels, but allows the user to examine the process and make real-time process corrections. Such software has already been used to monitor the emissions of many commercial/industrial

* One such program is *Software CEM*, a product of Pavilion Technologies, Inc., 12112 Technology Blvd., Austin, TX 78727-6298, tel: 512/250-3150, fax: 512/250-3180.

production processes: chemical production, food processing, pulp and paper manufacturing, to name a few. The equipment is inexpensive compared to the CEM technology (in some cases less than one tenth of the cost), and requires very little maintenance.

3 Summary and Recommendations

Using CEM technologies to meet State or Federal emissions requirements implies a dynamic collaboration of several principal elements:

1. An appropriately chosen CEM technology
2. A regular program of tracking, recordkeeping, and reporting
3. Careful review of the requirements of the specific State or Federal regulating agency.

This study outlined available CEM technologies to help installation design engineers and energy plant personnel select appropriate technologies for tracking, recording, and reporting emissions of criteria pollutants according to State and Federal EPA requirements. A complete summary of emissions regulations and required sampling, recordkeeping, and reporting procedures previously compiled by the Electric Power Research Institute (EPRI) has also been reprinted (with permission) as Appendixes A, C, and D to this report.

It is recommended that military installations considering the installation of CEM equipment:

1. Determine if there is a regulatory requirement to install CEMs based on the installation's (State or local) location or on the size of the operation.
2. If it is found that CEMs are not a regulatory requirement, it is currently recommended that this technology *not* yet be installed. It would be ill-advised, for example, to add this equipment because manufacturers claim that it will reduce the installation's work load. At its current level of development, CEMs are maintenance intensive and require high levels of technical expertise in electronics and sensor equipment.
3. When researching possible purchase of CEM equipment, it is vital that installations seek out third-party technical or product reviews of the equipment under consideration. It cannot be overstated: the manufacturer's technical or sales documentation should never be the sole source of information on which to base such a critical purchase.

Terms and Abbreviations

Air toxics	Pollutants defined by the CAAA 1990 as causing health and environmental problems. The CAAA 1990 lists 198 air toxics.
BACT	Best available control technology
CAA	Clean Air Act (42 U.S.C. § 7401 et seq.)
CAAA	Clean Air Act Amendments (PL 101-549, 15 November 1990).
CAP	Criteria air pollutant
CEM	Continuous emissions monitoring
CFR	Code of Federal Regulations
COMS	Continuous opacity monitoring system
Criteria Pollutants:	The six pollutants defined by the CAAA 1990 as causing pollution problems across broad areas of the nation: sulfur dioxide, carbon monoxide, lead, ozone, nitrogen dioxide and particulates.
Diluent gas	Major gaseous component in pollutant mixture, in the case of fossil fuel units these are CO ₂ and O ₂ .
Emissions	Pollutants exhausted into the atmosphere by a source that are measured, recorded and reported to the EPA Administrator as required by 40 CFR Part 75.
FR	Federal Register
LAER	Lowest achievable emissions rate.
MACT	Minimum available control technology.
NAAQS	National Ambient Air Quality Standard.
NADB	National Allowance Data Base; established by Administrator of the EPA under §420 (4) (C) of the Clean Air Act.
NESHAPS	National Emissions Standards for Hazardous Air Pollutants.
NSPS	New Source Performance Standards
Opacity	The degree to which emissions obscure a background object.
RACT	Reasonably available control technology.
Source	Any governmental, institutional, commercial, or industrial structure, installation, plant, building or facility that emits or has the potential to emit any regulated air pollutant.
Unit	Fossil fuel combustion device.
USC	United States Code.

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Appendix A: Comparison of CFR 40, Part 75 Requirements With Other Regulations

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COMPARISON OF PART 75 REQUIREMENTS WITH OTHER REGULATIONS

Throughout the Part 75 promulgation process, EPA clearly stated that utilities must satisfy all monitoring requirements resulting from the Acid Rain Rule in addition to any other applicable federal or state monitoring requirements. The regulations in Part 75 do not, in any way, supersede or modify other existing regulations.

During the review and comment period for proposed Part 75, the utility industry opposed many unnecessary differences (that would result in significantly higher costs to comply with federal and state monitoring requirements) between Part 75 and other existing regulations, and recommended changes to reduce or resolve differences between these various regulations. EPA, in response to over 2,700 comments received, modified numerous Part 75 procedures and specifications (e.g., calculation procedures and cylinder gas range specifications for linearity checks) prior to promulgation. However, significant differences remain between the promulgated version of Part 75 and other monitoring requirements applicable to the utility industry.

Some of the differences involve (1) more rigorous QA/QC monitoring requirements, (2) less tolerant performance specifications, (3) additional monitoring requirements, (4) expanded recordkeeping requirements, and (5) new (additive) reporting requirements. For example (1) semiannual (as opposed

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to annual) RATAs are required under some circumstances; (2) CEM systems must have a 10% relative accuracy (as opposed to 25%); (3) volumetric flow, stack, temperatures, and for some types of CEM systems moisture, must be monitored continuously for Part 75; (4) a written record of all operational data, corrective actions, maintenance, and calibration gas Protocol 1 certificates must be maintained onsite for three years; and (5) quarterly reports for Part 75 contain more information and must be submitted by a designated representative using a new electronic data reporting format.

The tables in this section summarize the Part 75 regulations discussed in Section 2 of this Guidelines Manual and also describe any differences or additional monitoring regulations required under 40 CFR Part 60 or 40 CFR Part 51. There are five sets of tables that compare QA requirements, equipment and performance specifications, recordkeeping, reporting, and notification requirements, respectively. Note that this section does not address specific state requirements. When evaluating the impact of state requirements on a utility's compliance monitoring program, the utility may want to add a column of additional regulations to each of these tables for comparative purposes.

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Regulatory Comparison

Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da	40 CFR Part 51 Appendix P
Daily Two-Point Calibration Error (CE) Test or Calibration Drift (CD) Test				
Definition	CE (§ 72.2)	CD (App. F, S. 2.5)	CD (§ 60.13(d))	CD (App. P, S. 3.7)
Test Conditions	0-20% and 80-100% of span (App. B, S. 2.1.1; App. A, S. 5.2)	0-20% and 80-100% of span (App. B, PS2, S. 4.1)	0-20% and 50-100% of span (§ 60.13(d))	As per manufacturer's recommendations (App. P, S. 3.7)
Procedures	<p>Use NIST/EPA-approved CRMs, SRMs or Protocol 1 cal gases (App. B, S. 2.1.1; App. A, S. 6.3.1)</p> <p>For dual-span or auto-ranging monitors, perform the daily calibration error test on each range used since the previous calibration error test. If the emission concentration has not exceeded the low-scale span value (based on maximum expected concentration) for more than one hour the cal error test may be performed at the low-scale only (App. B, S. 2.1.1)</p> <p>Inject the zero- and high-level concentrations once each at approximately 24-hour intervals (App. A, S. 2.2.1; App. A, S. 6.3.1)</p> <p>Calculate CE using monitor span values (App. A, S. 7.2)</p>	EPA Protocol 1 gas not required	EPA Protocol 1 gas not required	As per manufacturer's recommendations (App. P, S. 3.7)
		Calculate CD using monitor span values (App. B, S. 4.2)	Calculate CD using monitor span values (App. B, S. 4.2)	Calibration gases must be NBS traceable; reanalyzed every six months (unless otherwise guaranteed) (App. P, S. 3.3)

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Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da	40 CFR Part 51 Appendix P
Daily Two-Point CE Test or CD Test (continued)				
Recalibration	<p>Pollutant monitors: CE > 2.5% of instrument span if span value \geq 200 ppm; or CE > 5 ppm mean difference between monitor response value and the reference value if span value is < 200 ppm</p> <p>Diluent monitors: CE > 0.5% O₂ or CO₂ (App. A, S. 3.1)</p>	<p>Pollutant monitors: CD > 5.0% of monitor span</p>	<p>Pollutant monitors: CD > 5.0% of monitor span</p>	<p>Pollutant monitors: CD > 2.5% of monitor span</p>
Out-of-control Definition	<p>Pollutant monitors: CE > 5.0% if span value is \geq 200 ppm; or CE > 10 ppm for span value < 200 ppm</p> <p>Diluent monitors: CE > 1.0% O₂ or CO₂ (App. B, S. 2.1.5)</p>	<p>Diluent monitors: CD > 1.0% O₂ or CO₂ (App. F, S. 4.1)</p> <p>Pollutant monitors: CD > 5.0% of span for 5 consecutive days or > 10.0% of span for any one day</p> <p>Diluent monitors: CD > 1.0% O₂ or CO₂ for 5 consecutive days or > 2.0% O₂ or CO₂ for any one day (App. F, S. 4.3)</p>	<p>Diluent monitors: CD > 1.0% O₂ or CO₂ (§ 60.13(d))</p> <p>Not applicable</p>	<p>Diluent monitors: CD > 0.5% O₂ or CO₂ (App. P, S. 3.7)</p> <p>Not applicable</p>
Out-of-control Period	Beginning with hour of failed CE test and ending with hour of satisfactory CE test, following recalibration or corrective action (App. B, S. 2.1.5)	Beginning upon completion of any failed CD test (one or 5-day) and ending upon completion of a satisfactory CD test following corrective action (App. F, S. 4.3.1)	Not applicable	Not applicable

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Regulatory Comparison

Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors (continued)

Requirements		40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D ^a	40 CFR Part 51 Appendix P
Quarterly Linearity Check		Quarterly Three-point LE Checks Not Required by These Regulations			
Definition		CE (§ 72.2)			
Test Conditions		20-30%, 50-60%, and 80-100% of span (App. B, S. 2.2.1; App. A, S. 6.2; App. A, S. 5.2)			
Procedures		Use NIST/EPA-approved CRMs, SRMs or Protocol 1 calibration gas (App. A, S. 6.2) For units using emission controls or maximum expected concentration value, test both ranges of dual-range monitors (App. A, S. 6.2) Inject each calibration gas three times (not in succession) (App. A, S. 6.2) Calculate LE using calibration gas values (App. A, S. 7.1)			
Out-of-control Definition		Pollutant Monitors: Error in linearity exceeds or deviates from reference value > 5.0%; or if the mean difference between averages of monitor and reference values > 5 ppm			

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Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da	40 CFR Part 51 Appendix P
<i>Quarterly Three-point LE Checks Not Required by These Regulations</i>				
Quarterly Linearity Check (continued)				
Out-of-control Definition (continued)	Diluent monitors: Error in linearity exceeds or deviates from reference value > 5.0%; or if the mean difference between averages of monitor and reference values > 0.5% CO ₂ or O ₂ (App. B, S. 2.2.3; App. A, S. 3.2)			
Out-of-control Period	Beginning with hour of failed linearity check and ending with hour of satisfactory linearity check, following corrective action and/or monitor repair (App. B, S. 2.2.3)			
Relative Accuracy Test Audit (RATA)				
Applicability	SO ₂ and CO ₂ concentration monitors, only (App. B, S. 2.3.1)	All pollutant and diluent monitors		All pollutant and diluent monitors
Frequency	Semiannual ^b and Annual (App. B, S. 2.3)	Once every 4 quarters (Annual) (App. F, S. 5.1.1)		*The State may require proof of continuous monitoring of system performance whenever system repairs or adjustments have been made. Test procedures and limitations are not specified. (App. P, S. 4.4)

RATAs Not Required by
This Regulation

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Regulatory Comparison

Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da	40 CFR Part 51 Appendix P
Relative Accuracy Test Audit (RATA) (continued)				
Test Conditions	<p>Semiannual: SO₂ and CO₂ concentration of RATAs performed at one level (normal operating)^c</p> <p>Completion of RATA within a 7-day period</p> <p>Annual: SO₂ and CO₂ concentration RATAs performed at one level (normal operating)^c</p> <p>Completion of RATA within a 7-day period</p> <p>(App. B, S. 2.3.1; App. A, S. 6.5)</p>	<p>Not applicable</p> <p>Not applicable</p> <p>> 50% or normal load (App. B, PS 2, S. 5.3)</p> <p>Not applicable</p>	<p>RATAs Not Required by This Regulation</p>	<p>Not applicable</p>
Number of Reference Method (RM) Tests	<p>Nine sets (minimum), of RM and CEM data^d (App. A, S. 6.5.9)</p> <p>A maximum of two 9-run RATA sets may be performed to qualify for annual audit only. The results of the second test shall be used in calculating relative accuracy and bias (App. B, S. 2.3.1)</p>	<p>Nine sets of RM and CEM data^d (App. F, S. 7.3)</p> <p>Not applicable</p>		<p>Not applicable</p>
Bias Adjustment	<p>Apply bias adjustment factor given by Eq. A-11 prospectively to the data from the time of the failed bias test until the time of a RATA that does not show bias (App. A, S. 7.6.5)</p>	<p>Not applicable</p>		<p>Not applicable</p>

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Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da	40 CFR Part 51 Appendix P
Relative Accuracy Test Audit (RATA) (continued)				
Out-of-control Definition	RA > 10.0% for SO ₂ concentration monitor when average SO ₂ measured is > 250 ppm or for low SO ₂ emitting situations (≤ 250 ppm average measured SO ₂) the mean CEM value exceeds ± 15 ppm of mean RM value (App. B, S. 2.3.2) low SO ₂ emitter (≤ 250 ppm) is referenced in App. A, S. 3.3.1	RA > 20% of mean RM test data or > 10% of applicable standard (App. F, S. 5.2.3) ^e	RATAs Not Required by This Regulation	Not applicable
Out-of-control Period	Beginning with hour of completion of failed RATA and ending with the hour of completion of a satisfactory RATA (App. B, S. 2.3.2)	Beginning with the completion of a failed RATA, and ending with the completion of a subsequent successful RATA (App. F, S. 5.2.1)		Not applicable
Cylinder Gas Audits (CGA)	CGAs Not Required by This Regulation			Cylinder Gas Audits Not Required by These Regulations
Frequency		3 of 4 calendar quarters, with no more than 3 in succession (App. F, S. 5.1.2)		
Test Conditions		20-30% and 50-60% of span value for pollutant monitors (App. F, S. 5.1.2) ^f		
Test Conditions (continued)		5-8% and 10-14% CO ₂ by volume for CO ₂ diluent monitors (App. F, S. 5.1.2)		
		4-6% and 8-12% O ₂ by volume for O ₂ diluent monitors (App. F, S. 5.1.2)		

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Regulatory Comparison

Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D ^a	40 CFR Part 51 Appendix P
Cylinder Gas Audits (CGA) (continued)	CGAs Not Required by This Regulation			Cylinder Gas Audits Not Required by These Regulations
Procedures		<p>Use EPA Protocol 1 calibration gas (App. F, S. 5.1.2)</p> <p>Inject each calibration gas three times (not in succession) (App. F, S. 5.1.2)</p>		
Out-of-control Definition		CGA > 15% of the average audit value or > 5 ppm (App. F, S. 5.2.3)		
Out-of-control Period		Beginning at the time of completion of a failed CGA, and ending at the time of completion of a successful CGA (App. F, S. 5.2.1)		
Relative Accuracy Audits (RAA)	RAAs Not Required by This Regulation			Relative Accuracy Audits Not Required by These Regulations
Frequency			3 of 4 calendar quarters in lieu of CGA, with no more than 3 in succession (App. F, S. 5.1.3)	
Test Conditions			> 50% or normal load (App. B, PS2, S. 5.3)	
Out-of-control Definition			RAA > 15% of 3-run average of RM test data or > 7.5% of applicable standard (App. F, S. 5.2.3)	

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Table 3-1A
Quality Assurance Procedures for Pollutant and Diluent Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da ^a	40 CFR Part 51 Appendix P
Relative Accuracy Audits (RAA) (continued)	RAAs Not Required by This Regulation		Relative Accuracy Audits Not Required by These Regulations	
Out-of-control Period		Beginning with the completion of a failed RAA, and ending with the completion of a successful RAA (App. F, S. 5.2.1)		

- a Subpart D CEM system data are used for compliance by the cognizant state agency. QA requirements under Subpart Da/Appendix F may be applicable (§ 60.13(a)).
- b Semiannually, except that a RATA may be performed during the fourth quarter, rather than semiannually during the second quarter, following a previous RATA for which the relative accuracy is $\leq 7.5\%$.
- c (1) Low-level: between minimum safe and stable operating level and 50% load; (2) high-level: frequently used high operating level between 80% of maximum operating level and maximum operating level; (3) mid-level: normal operating level, or an evenly spaced intermediate level if the normal operating level is within 10.0% of the low- or high-level.
- d Test duration is 30-60 minutes for Part 75 and 21-minute (minimum) for Subpart Da, and for both, more than nine sets of data can be obtained and up to three sets can be rejected, but all sets must be reported and a minimum of nine tests must be used.
- e In addition, where RA is $> 15\%$ of applicable standard if standard is ≥ 0.2 and < 0.3 lb/MMBtu; or where RA is $> 20\%$ of applicable standard if standard is < 0.2 lb/MMBtu (App. B, PS2, S. 4.3).
- f These calibration gas ranges are identical to the low- and mid-level gases used for Part 75 linearity checks.

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Table 3-1B
Quality Assurance Procedures for Flow Monitors

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Flow Monitors Not Required By These Regulations				
Daily Two-point Calibration Error (CE) Tests				
Applicability	Applies to <i>all</i> flow monitors (App. B, S. 2.1.2; App. A, S. 2.2.2.1)			
Test Conditions	0-20% of span or an equivalent reference value and 50-70% of span (App. A, S. 2.2.2.1)			
Procedures	Perform CE at least once each unit operating day (App. B, S. 2.1.2) Record flow monitor output before and after any adjustments (App. B, S. 2.1.2) Calculate CE using Eq. A-6 in App. A of this part (App. B, S. 2.1.2)			
Recalibration	CE > 3.0% based upon the span of the instrument (App. B, S. 2.1.4; App. A, S. 3.1)			
Out-of-control Definition	CE > 6.0% based upon the span of the instrument (App. B, S. 2.1.5)			
Out-of-control Period	Beginning with the hour of the failed CE test, and ending with the hour of completion of the satisfactory CE test following recalibration or corrective action (App. B, S. 2.1.5)			
Daily Interference Check				
Applicability	Applies to <i>all</i> flow monitors (App. B, S. 2.1.3; App. A, S. 2.2.2.2)			
Flow Monitors Not Required By These Regulations				

Flow Monitors Not Required By These Regulations

Flow Monitors Not Required By These Regulations

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Table 3-1B
Quality Assurance Procedures for Flow Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Daily Interference Check (continued)	<p><i>Flow Monitors Not Required By These Regulations</i></p> <p>Differential pressure: perform daily automatic periodic backpurging and provide a means for detecting system leaks on a quarterly basis (App. B, S. 2.1.3; App. A, S. 2.2.2.2)</p> <p>Thermal: inspect and clean monitor probes (daily if necessary) (App. B, S. 2.1.3; App. A, S. 2.2.2.2)</p> <p>Ultrasonic: perform daily cleaning of transceivers (e.g., backpurging system) (App. B, S. 2.1.3; App. A, S. 2.2.2.2)</p> <p>When an interference is identified (App. B, S. 2.1.5) (Subject to interpretation)</p> <p>Beginning with the hour of completion of the failed interference check and ending with the hour of completion of an interference check (App. B, S. 2.1.5)</p>			
Procedures				
Out-of-control Definition				
Out-of-control Period				
Quarterly Leak Check	<p><i>Flow Monitors Not Required By These Regulations</i></p> <p>Differential pressure flow monitors (App. B, S. 2.2.2)</p> <p>Perform leak check of all sample lines (App. B, S. 2.2.2)</p> <p>When a flow monitor sample line leak is detected (App. B, S. 2.2.3) (Subject to interpretation)</p>			
Applicability				
Procedure				
Out-of-control Definition				

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Regulatory Companion

Table 3-1B
Quality Assurance Procedures for Flow Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Quarterly Leak Check (continued)				
Out-of-control Period	Begins with the hour of the failed leak check and ends with the hour of a satisfactory leak check following corrective action (App. B, S. 2.2.3)	Flow Monitors Not Required By These Regulations		
Semiannual and Annual RATAs^a				
Applicability	For all flow monitors, one-level and three-level RATAs are performed alternately when required, such that the three-level RATA is performed at least once annually. A one-level semiannual RATA requirement will apply when any or all of the three-level annual flow RATAs fails to meet the specifications for reduced testing (App. B, S. 2.3.1) The one-level audit is performed at the normal operating level and the three-level audit is performed at three different operating levels defined in App. A, S. 6.5.2 (App. B, S. 2.3.1) ^b Nine sets of RM and flow monitor data performed at each operating level tested ^c (App. A, S. 6.5.9)	Flow Monitors Not Required By These Regulations		
Test Conditions				
Number of Reference Method (RM) Tests				
Bias Adjustment	Apply bias adjustment factor given by Eq. A-11 and A-12 (App. A, S. 7.6.5) prospectively to the data from the time of the RATA that failed the bias test until the next RATA that does not show bias (App. B, S. 2.4)			

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Table 3-1B
Quality Assurance Procedures for Flow Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Semiannual and Annual RATA (continued)				
<i>Flow Monitors Not Required By These Regulations</i>				
Out-of-control Definition	RA > 15.0% prior to January 1, 2000; or RA > 10.0% on or after January 1, 2000; or for low flow conditions (≤ 10.0 fps) when the flow monitor mean value (if applicable) exceeds ± 2.0 fps of the RM mean (App. B, S. 2.3.2)			
Out-of-control Period	For flow RATAs performed at one level: Beginning with the hour of completion of the failed RATA and ending with the hour of completion of a satisfactory RATA following corrective action or repair of the monitor (App. B, S. 2.3.2)			
	For flow RATAs at 3 levels: Beginning with the hour of completion of the first failed RATA at any of the 3 levels and ending with the completion of a satisfactory 3-level RATA. (App. B, S. 2.3.2)			

a Semiannually, except that a RATA may be performed during the fourth quarter only, rather than semiannually during the second quarter, following a previous RATA for which the RA is $\leq 10.0\%$ (prior to January 1, 2000) or $\leq 7.5\%$ (on or after January 1, 2000) of each operating level tested. Also, on low flow (≤ 10.0 fps) stacks/ducts when the monitor mean is ± 1.5 fps of the reference mean. (App. B, S. 2.3.1).

b Low-level: between minimum safe and stable operating level and 50% load. High-level: between 80% of the maximum operating level and the maximum operating level. Mid-level: Normal operating level. If normal operating level is within 10% maximum operating level of low- or high-loads, choose an evenly spaced mid-level.

c Conduct each set within 30-60 minutes at each required level. A minimum of nine sets of data must be obtained; more than nine sets can be obtained, and up to three sets can be rejected. All sets of data must be reported. For certification and annual QA RATAs perform minimum of 9 sets at each of three operating levels.

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Regulatory Comparison

Table 3-1C

Quality Assurance Procedures for Combined Pollutant-Diluent CEM Systems

Requirements		40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da	40 CFR Part 51 Appendix P
Semiannual and Annual Relative Accuracy Test Audits					
Applicability		Combined NO _x -diluent CEM systems, (Also SO ₂ -diluent CEM systems used by units with Phase I qualifying technology for the period during which the units are required to monitor SO ₂ removal efficiency, from Jan. 1, 1997 - Dec. 31, 1999) (App. B, S. 2.3.1)	Combined SO ₂ -diluent and NO _x -diluent CEM systems (App. F, S. 5.1.1)		Combined Pollutant-Diluent CEM System Not Required
Frequency		Semiannual/Annual ^b	Annual		
Test Conditions		One level (defined as "normal operating level" App. A, S. 6.5.2) (App. A, S. 6.5.1)	> 50% normal load (App. B, S. 5.3)		
Number of RM Tests		A minimum of nine sets of RM and CEM system data (App. A, S. 6.5.9) ^c	Nine sets of RM and CEM system data (App. B, S. 7.3) Both sets in units of lb/MBtu (App. B, S. 5.3)		
Bias Adjustment Factor		Apply bias adjustment factor given by Eqs. A-11 and A-12 (App. A, S. 7.6.5) prospectively to the data from the date and time of the failed bias test until the date and time of the next RATA that does not show bias (App. B, S. 2.3.2)	Not applicable		
Out-of-control Definition		RA > 10.0% in units of lb/MBtu; and for low-NO _x emitting units (≤ 0.2 lb/MBtu), when the NO _x CEM system values exceed ± 0.02 lb/MBtu of the RM mean and for low-SO ₂ emitting units (≤ 0.5 lb/MBtu), when the SO ₂ CEM system values exceed ± 0.03 lb/MBtu of the RM mean. (App. B, S. 2.3.2)	RA > 20% (in lb/MBtu) or 10% of applicable standard (App. F, S. 5.2.3 and App. B, S. 5.3)		

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Table 3-1C
Quality Assurance Procedures for Combined Pollutant-Diluent CEMSs (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Out-of-control Period	Beginning with the hour of the failed RATA and ending with the hour of completion of a satisfactory RATA following corrective action or repair of the monitoring system (App. B, S. 2.3.2)	Beginning with failed RATA and ending with a satisfactory RATA following corrective action (App. F, S. 5.2)		

- a If Subpart D CEM system data are used for compliance by the cognizant state agency, QA requirements under Subpart Da/Appendix F may be applicable (§ 60.13(a)).
- b Semiannually, except that a RATA may be performed during the fourth quarter, rather than semiannually during the second quarter; (1) following a previous RATA for which the RA is $\leq 7.5\%$ of the RM mean, or (2) on low-SO₂ emitting units (≤ 250 ppm) when the monitor mean is within ± 8.0 ppm (or equivalent in lb/MBtu).
- c Conduct each set within 30-60. A minimum of nine test sets is required; more than nine sets of data can be obtained, and up to three sets can be rejected. All sets of data must be reported.

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Regulatory Comparison

Table 3-1D
Quality Assurance Procedures for Opacity Monitors

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 ^a Appendix M
Daily Two Point Calibration Error (CE) Test or Calibration Drift (CD) Test				
Definition	CE (§ 75.3)	CD (App. F, S.2.5)	CD (§ 60.13(d))	CD (App. P, S.3.7) CE (App. M, S.5.7)
Test Conditions	Operate, calibrate and maintain according to SIPs, pursuant to App. M (§ 75.21)	Zero- or (low) level and high level (App. B, PS1, S.5.1.5)	As per manufacturer's recommendations (App. P, S.3.7)	As per PS1 (App. M, S.5.1)
Procedures	(§ 75.21)	As per PS1 (App. F, S.4.1)	As per PS1 (§ 60.13)	As per PS1 (App. M, S.4.1)
Recalibration				Exceeds PS1 specifications (App. M, S.5.1)
Out-of-control Definition		CD > 4.0% of span for five consecutive days or 8.0% of span for any one day (App. F, S.4.3)	Not applicable	Twice PS1 specifications (App. M, S.2.3.1)
Out-of-control Period		Beginning upon completion of any failed CD test (one or 5-day) and ending upon completion of a satisfactory CD test following corrective action (App. F, S.4.3)		Beginning time corresponding to the last successful drift check and ending with a successful drift check, following adjustments (App. M, S.2.3.2)
Fault Lamp Indicator Check		Not Required in This Regulation	Not Required in This Regulation	
Frequency				Quarterly (App. M, S.5.2)

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Table 3-1D
Quality Assurance Procedures for Opacity Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 ^a Appendix M
Fault Lamp Indicator Check (continued)				
Procedures				Check system self-diagnostic indicators, error messages, fault lamps, if illuminated data is invalid (App. M, S.4.3)
Out-of-control Definition				Not specified
Out-of-control Period				Not specified
Optical Alignment Assessment		Not Required in This Regulation	Not Required in This Regulation	Quarterly (App. M, S.5.3.1)
Frequency				As per manufacturer's procedures (App. M, S.5.3.1)
Procedures				Value > 2.0% (App. M, S.5.5.1)
Out-of-control Definition				Beginning with the time corresponding to the completion of the audit indicating unacceptable performance and ending with a successful audit, following corrective actions (App. M, S.2.3.2)
Out-of-control Period				(App. M, S.5.3.2)
Optical Surface Dust Accumulation Assessment		Not Required in This Regulation	Not Required in This Regulation	Quarterly (App. M, S.5.3.2)
Frequency				

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Regulatory Comparison

Table 3-1D
Quality Assurance Procedures for Opacity Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 ^a Appendix M
Optical Surface Dust Accumulation Assessment (continued)				
Procedures				Apparent effluent opacity is compared & recorded before and after each optical cleaning. Total optical surface dust accumulation value equals sum of opacity reductions for each optical surface cleaned. ^b
Out-of-control Definition				Value > 4.0% (App. M, S.5.5.1)
Out-of-control Period				Beginning with the time corresponding to the completion of the audit indicating unacceptable performance and ending with a successful audit, following corrective actions (App. M, S.2.3.2)
Zero and Upscale Response Assessment				(App. M, S.5.3.3)
Frequency		Not Required in This Regulation	Not Required in This Regulation	Quarterly (App. M, S.5.3.3)
Procedures				According to the calibration drift procedures (App. M, S.5.3.3)
Out-of-control Definition Value				> 2.0% (App. M, S.5.5.1)

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Table 3-1D

Quality Assurance Procedures for Opacity Monitors (continued)

Requirements	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 ^a Appendix M
Zero and Upscale Response Assessment (continued)			
Out-of-control Period	Not Required in This Regulation	Not Required in This Regulation	(App. M, S.5.3.3) Beginning with the time corresponding to the completion of the audit indicating unacceptable performance and ending with a successful audit, following corrective actions (App. M, S.2.3.2)
Zero Compensation Assessment			
Frequency	Not Required in This Regulation	Not Required in This Regulation	Quarterly (App. M, S.5.3.4)
Procedures			As per manufacturer's recommendations (App. M, S.5.3.4)
Out-of-control Definition			Value > 4.0% (App. M, S.5.5.1)
Out-of-control Period			Beginning with the time corresponding to the completion of the audit indicating unacceptable performance and ending with a successful audit, following corrective actions (App. M, S.2.3.2)
Stack Exit Correlation Assessment			
Frequency	Not Required in This Regulation	Not Required in This Regulation	Quarterly (App. M, S.5.3.5)

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Regulatory Comparison

Table 3-1D
Quality Assurance Procedures for Opacity Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 ^a Appendix M
Stack Exit Correlation Assessment (continued)				
Procedures		Not Required in This Regulation	Not Required in This Regulation	Compare monitor path-length and stack exit diameter. Error is the absolute value of the difference between measured value & correct value. (App. M, S.5.3.5)
Out-of-control Definition				Value > 2.0% (App. M, S.5.5.1)
Out-of-control Period				Beginning with the time corresponding to the completion of the audit indicating unacceptable performance and ending with a successful audit, following corrective actions (App. M, S.2.3.2)
Calibration Error Test				
Frequency		Not Required in This Regulation	Not Required in This Regulation	Quarterly (App. M, S.5.3.6)
Procedures				Primary method ^c Alternative method ^d Additional guidance in PS1 (S. 7) Applicable filter ranges ^e Value > 2.0% (App. M, S.5.5.1)
Out-of-control Definition				

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Table 3-1D
Quality Assurance Procedures for Opacity Monitors (continued)

Requirements	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 ^a Appendix M
Calibration Error Test (continued)			
Out-of-control Period	Not Required in This Regulation	Not Required in This Regulation	Beginning with the time corresponding to the com- pletion of the audit indicat- ing unacceptable perfor- mance and ending with a successful audit, following corrective actions (App. M, S.2.3.2)
Zero Alignment Assessment			
Frequency	Not Required in This Regulation	Not Required in This Regulation	Annually (App. M, S.5.4)
Procedures			Primary method ^f Alternative method ^g As per procedures in EPA -600/8-87-025, S. 10, ^h Value > 5.0% for one check Value > 2.0% for three consecutive checks (App. M, S.5.5.1 & S.5.5.5) ⁱ
Out-of-control Definition			Beginning with the time corresponding to the com- pletion of the audit indicat- ing unacceptable perfor- mance and ending with a successful audit, following corrective actions (App. M, S.2.3.2)
Out-of-control Period			

Footnotes - Table 3-1D

- a The Appendix M QA procedures and requirements are included in Proposed Method 203 which will be added to Appendix M upon promulgation. These QA requirements may not currently be required by some states. Examples of detailed audit procedures are provided in EPA's 600/8-87-025 "Performance Audit Procedures For Opacity Monitors", May 1986. An updated version of this document, EPA 450/4-92-010, was published April 1992.
- Calculations provided in Performance Specification 1, Section 8, shall be followed for the audits described in Appendix M. (App. M, S.6.1)
- Whenever unacceptable performance values are obtained for an audit for two consecutive quarters, the owner or operator must increase or modify the QC procedures or replace the opacity monitor. (App. M, S.5.5.4)
- b Fluctuations in the effluent opacity occurring during the cleaning cycle can adversely affect the audit results. (App. M, S.5.3.2)
- c The primary calibration error method specifies the use of a zero-jig in conjunction with the neutral density filters. (App. M, S.5.3.6.1)
- d The alternative calibration error method requires that the neutral density filters be superimposed over the effluent opacity. The expected filter value and the opacity value immediately preceding the filter superimposing are then compared. This procedure is subject to the adverse affects of fluctuations in the effluent opacity. (App. M, S.5.3.6.2)
- e Neutral density filter values determined as specified in Performance Specification 1. Filters shall be checked at least once per year and are considered stable if the check indicates a change of less than 2.0%. (App. M, S.5.3.6.3 and S.5.3.6.4)
- f The primary zero alignment method is performed under clear stack conditions. The audit is performed annually unless the opacity monitor allows the use of a zero-jig, in which case the audit will be conducted once every three years. (App. M, S.5.4.2)
- g The alternate zero alignment method specifies the use of a zero-jig, provided that the zero-jig setting has been established for the monitor pathlength and recorded for the specific opacity monitor by comparison of the opacity monitor's responses to the installed zero-jig and to the clear path condition. A primary zero alignment audit must still be performed once every three years. (App. M, S. 5.4.2)
- h Conduct audit according to EPA 600/8-87-025, Section 10 or Section 11 of EPA 450/4-92-010. (App. M, S.6.2)
- i Following an unacceptable zero alignment assessment, the utility must either conduct a zero alignment audit twice per year during non-consecutive quarters, or replace the opacity monitor. (App. M, S.5.5.5)

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Table 3-2A
Equipment Specifications for Pollutant and Diluent Monitors^a

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Data Recorder Scale	Not specified	From zero to a "high-level," which must fall between 90% and 100% of the full scale of the recorder (except where digital recorders are used) For CEM systems measuring uncontrolled emissions, the "high-level" value must also be between 125% and 200% of the average potential emission level ^b	From zero to a "high-level," which must fall between 90% and 100% of the full scale of the recorder (except where digital recorders are used) For CEM systems measuring uncontrolled emissions, the "high-level" value must also be between 125% and 200% of the average potential emission level ^b	Not specified
Calibration Gas Injection Point	Must allow a check of the entire measurement system ^c (App. A, S. 2.2.1)	At a minimum, must allow injection between the probe and sample line ^c (App. F, S. 5.1.2(2))	For CEM systems measuring controlled emissions, the "high-level" value must also be between 150% of the value corresponding to the emission standard and the CEM span value (App. B, PS2, S. 4.1 and PS3, S. 2.1) (Subject to interpretation)	Not specified

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Regulatory Comparison

Table 3-2A
Equipment Specifications for Pollutant and Diluent Monitors^a (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
NO _x Monitor Span Value	Must be ≥ the span value of 125% of the maximum potential concentration (MPC) ^d (App. A, S. 2.1.2.1) Auto-ranging NO _x monitors must be capable of measuring up to 125% of the MPC as defined in section 2.1.2.1 (App. A, S. 2.1.2.3)	Gas fuel: 500 ppm Liquid fuel: 500 ppm Solid fuel: 1000 ppm Combination fuels: 500 (x+y) + 1000z ^e (\$ 60.47a(i)(3))	Gas fuel: 500 ppm Liquid fuel: 500 ppm Solid fuel: 1000 ppm Combination fuels: 500 (x+y) + 1000z ^e (\$ 60.45(c)(3))	Approximately 200% of expected concentration at the level of the emission standard (App. P, S. 3.8)
NO _x Monitor Span Adjustment	Adjust full-scale range as needed to prevent exceedances. Multiply the new range setting by 80% and round to the nearest 100 ppm (or 10 ppm) to determine the new span value. (App. A, S. 2.1.2.4)	Not Applicable	Not Applicable	Not Applicable
SO ₂ Monitor Span Value (Inlet of Control)	Must be able to measure up to 125% of the maximum potential concentration (MPC) as calculated using Eq. A-1a or A-1b with the maximum percent sulfur and minimum GCV for the highest sulfur fuel to be burned. Multiply the MPC by 125% and round to the nearest 100 ppm to determine the span value. (App. A, S. 2.1.1.1)	125% of maximum estimated hourly potential emissions (\$ 60.47a(i)(5))	Not applicable	Not applicable

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Table 3-2AEquipment Specifications for Pollutant and Diluent Monitors^a (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
SO ₂ Monitor Span Value (Outlet of Control)	If most SO ₂ concentration values are predicted to be < 25% of full-scale range based upon 125% of MPC use a dual range analyzer. Determine the span value for the second range by using Eq. A-2 to calculate the maximum expected concentration (MEC). Multiply the MEC by 125% and round to the nearest 10 ppm. (App. A, S. 2.1.1.2)	50% of maximum estimated hourly potential emissions (\$ 60.47a(i)(5))	Liquid fuel: 1000 ppm Solid fuel: 1500 ppm Combination fuels: 1000 (x+y) + 1500z ^e (\$ 60.45(c)(3))	Approximately 200% of expected concentration at the level of the emission standard (App. P, S. 3.8)
SO ₂ Monitor Span Adjustment	Auto-ranging SO ₂ monitors must be capable of measuring up to 125% of the MPC as calculated using Eq. A-1a or A-1b (App. A, S. 2.1.1.3) Adjust full-scale range as needed to prevent exceedances. Multiply the new range setting by 80% and round to the nearest 100 ppm (or 10 ppm) to determine the new span value (App. A, S. 2.1.1.4)	Not Applicable	Not Applicable	Not Applicable
CO ₂ and O ₂ Monitor Span Value	20% for either diluent or use a dual range analyzer for increased accuracy at lower concentration levels. Multiply the "low-scale" range setting by 80% to determine low range span value. (App. A, S. 2.1.3)	Not Applicable	Not Applicable	Not Applicable

Footnotes - Table 3-2A

- a All CEM system equipment must be capable of performing all required QA procedures (See Table 1A).
- b If a lower "high-level" value is used, source must be able to measure emissions greater than full scale limit of the CEM system.
- c All monitoring components of the measurement system exposed to the sample gas including sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable.
- d NO_x maximum potential concentration (MPC):
 Use 800 ppm for coal-fired units (0-1000 ppm range)
 Use 400 ppm for oil- or gas-fired units (0-500 ppm range)
 If NO_x MPC is expected to be higher due to unit type or discovered through testing
 Use 1600 ppm for coal-fired units (0-2000 range)
 Use 480 ppm for oil- or gas-fired units (0-600 ppm range)
 If most NO_x concentration values are expected to be less than 25% of the full scale (based upon 125% of MPC) use a dual range analyzer and
 Use 320 ppm for coal-fired units (0-400 ppm range)
 Use 160 ppm for oil- or gas-fired units (0-200 ppm range)
- e x = Fraction of total heat input derived from gaseous fossil fuel.
 y = Fraction of total heat input derived from liquid fossil fuel.
 z = Fraction of total heat input derived from solid fossil fuel.
 Round calculated span value to nearest 500 ppm.

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Table 3-2B

Performance Specifications for Individual Pollutant and Diluent Monitors

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Calibration Error (CE)	Pollutant (SO ₂ & NO _x): ≤ 2.5% of instrument span; or if span value < 200 ppm, CE results are acceptable if mean difference between monitor and reference values ≤ 5 ppm Diluent (O ₂ or CO ₂): ≤ 0.5% from reference value (App. A, S. 3.1)	Pollutant (SO ₂ & NO _x): ≤ 2.5% of the monitor span value Diluent (O ₂ or CO ₂): ≤ 0.5% O ₂ or CO ₂ (App. F, S. 4.1)	Pollutant (SO ₂ & NO _x): ≤ 2.5% of the monitor span value Diluent (O ₂ or CO ₂): ≤ 0.5% O ₂ or CO ₂ (\$ 60.13(d))	Pollutant (SO ₂ & NO _x): ≤ 2.5% of the monitor span value Diluent (O ₂ or CO ₂): ≤ 0.5% O ₂ or CO ₂ (App. P, S. 3.7)
Linearity Check	Pollutant (SO ₂ & NO _x): ≤ 5.0% from reference value for each cal gas concentra- tion; or if mean difference between monitor and refer- ence value ≤ 5 ppm (Eq. A-4) Diluent (O ₂ or CO ₂) ≤ 5.0% from reference value of each cal gas concentration; or if mean difference be- tween monitor and refer- ence values are ≤ 0.5% (App. A, S. 3.2)	Not Applicable	Not Applicable	Not Applicable
Relative Accuracy (RA)	Pollutant (SO ₂ only): ≤ 10.0% when SO ₂ concen- tration is > 250 ppm; or the mean CEM value is within ± 15 ppm of the mean RM value when SO ₂ concentra- tion is ≤ 250 ppm (App. A, S. 3.3.1)	Pollutant (SO ₂ & NO _x): ≤ 20% of the mean value of the RM data or 10% of the applicable standard ^a (App. B, PS2, S. 4.3)	Pollutant (SO ₂ & NO _x): ≤ 20% of the mean value of the RM data or 10% of the applicable standard ^a (App. B, PS2, S. 4.3)	Pollutant (SO ₂ & NO _x): ≤ 20% of the mean value of the RM data or 10% of the applicable standard ^a (App. B, PS2, S. 4.3)

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Table 3-2B
Performance Specifications for Individual Pollutant and Diluent Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Relative Accuracy (RA) (continued)	Not applicable to individual NO _x monitors Diluent (CO ₂): ≤ 10.0% of RM mean value; or if mean difference between CEM and RM is within ± 1.0% CO ₂ (App. A, S. 3.3.3)	Diluent (O ₂ & CO ₂): ≤ 20% of RM mean value or ≤ 1.0% O ₂ or CO ₂ (App. B, PS3, S. 2.3)	Diluent (O ₂ & CO ₂): ≤ 20% of RM mean value or ≤ 1.0% O ₂ or CO ₂ (App. B, PS3, S. 2.3)	Diluent (O ₂ & CO ₂): ≤ 20% of RM mean value or ≤ 1.0% O ₂ or CO ₂ (App. B, PS3, S. 2.3)
Bias Adjustment	Bias adjustments for all SO ₂ monitors must be made for any calculated low bias (App. A, S. 3.4.1)	Not applicable	Not applicable	Not applicable
Cycle/Response Time ^b	≤ 15 min for all pollutant and diluent monitors (App. A, S. 3.5) Minimum of four data points required for a valid 1-hr average, except for periods of calibration and QA activities when a minimum of two data points will be allowed (75.10(d)(1))	≤ 15 min for all pollutant and diluent monitors (§ 60.13(e)(2)) At least two data points must be used to calculate 1-hr averages (§ 60.47a(g))	≤ 15 min for all pollutant and diluent monitors (§ 60.13(e)(2)) No minimum number of data points is established for 1-hr averages	≤ 15 min for all pollutant and diluent monitors (App. P, S. 3.4.2) No minimum number of data points is established for the 1-hr averages

^a In addition (for SO₂ monitors only), if the SO₂ standard is between 0.2 and 0.3 lb/MBtu, RA must be ≤ 15% of the applicable standard; and if the standard is below 0.2 lb/MBtu, the RA must be < 20% of the applicable standard (App. B, PS2, S. 4.3).

^b For combined monitoring systems (pollutant/diluent) the hourly average emission rate is valid only if the hourly average concentration from each component analyzer is valid (75.10(d)(1)).

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Table 3-2C
Equipment and Performance Specifications for Flow Monitors

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Equipment Specifications	<i>Flow Monitors Not Required by These Regulations</i>			
Monitor Design	<p>All flow monitors must be capable of performing all required QA procedures (See Table 1B)</p> <p>All flow monitors must provide a method or mechanism for zeroing and calibrating the entire flow monitoring system (probe tip to DAS) or the transducer through the DAS (App. A, S. 2.2.2.1)</p> <p>All flow monitors should not be affected by moisture interference</p> <p>All flow monitors should be able to detect, on a daily basis, pluggage of the sample line or sensing port and malfunction in the resistance temperature detector (RTD), transceiver or equivalent</p> <p>Differential pressure flow monitors must provide an automatic periodic back purge on a daily basis</p> <p>Differential pressure flow monitors must provide a means for leak detection on a minimum quarterly basis</p> <p>Thermal flow monitors must provide a means for ensuring the probe remains clean on a daily basis</p> <p>Ultrasonic flow monitors must provide a means to ensure that the transceivers remain sufficiently clear (e.g., backpurging system) on a daily basis (App. A, S. 2.2.2.2)</p>			

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Table 3-2C
Equipment and Performance Specifications for Flow Monitors (continued)

Requirements	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Equipment Specifications (continued)				
Instrument Span	Determine the span value by multiplying the maximum potential velocity (MPV) as determined by previous tests or calculations by 125%; or calculate the MPV using Eq. A-3a or A-3b and then multiply by 125% rounding up to the nearest multiple of 100 fpm (App. A, S. 2.1.4)	Flow Monitors Not Required by These Regulations		
Performance Specifications				
Calibration Error (CE)	CE \leq 3.0% of instrument span as calculated using Eq. A-6 for at least two reference values (0-20% and 50-70% of span) (App. A, S. 3.1)	Flow Monitors Not Required by These Regulations		
Relative Accuracy (RA)	<p>Prior to January 1, 2000: RA \leq 15.0% when the gas velocity is > 10.0 fps</p> <p>or</p> <p>Mean flow monitor value shall not exceed ± 2.0 fps of mean RM value when the gas velocity is ≤ 10.0 fps</p> <p>On or after January 1, 2000: RA $\leq 10.0\%$ when the gas velocity is > 10.0 fps</p> <p>or</p> <p>Mean flow monitor value shall not exceed ± 2.0 fps of mean RM value when the gas velocity is ≤ 10.0 fps (App. A, S. 3.3.4)</p> <p>Bias adjustments for flow monitors must be made for any calculated low bias (App. A, S. 3.4.2)</p>	Flow Monitors Not Required by These Regulations		
Bias Adjustment		Flow Monitors Not Required by These Regulations		

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Table 3-2D
Performance Specifications for Combined SO₂-Diluent CEM Systems and Combined NO_x-Diluent CEM Systems

Requirements	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Combined NO_x-Diluent and SO₂-Diluent CEM Systems			
Relative Accuracy (RA)	<p>RA ≤ 10.0% when the NO_x emission rate is > 0.20 lb/MBtu or SO₂ emission rate is > 0.50 lb/MBtu</p> <p>or</p> <p>Mean CEM value is within ± 0.02 lb NO_x/MBtu or 0.03 lb SO₂/MBtu of the mean RM value (App. A, S. 3.3.2)</p>	≤ 20% of the mean value of the RM data or 10% of the applicable standard	≤ 20% of the mean value of the RM data or 10% of the applicable standard
Cycle/Response Time	≤ 15 minutes (App. A, S. 3.5). Gases must be injected simultaneously to determine pollutant-diluent system response	≤ 15 minutes (§ 60.13(e)(2))	≤ 15 minutes (App. P, S. 3.4.2)
Bias Adjustment	Bias adjustments for combined NO _x -diluent CEM systems must be made for any calculated low bias (App. A, S. 3.4.1)	Not applicable	Not applicable

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Table 3-2E
Equipment and Performance Specifications for Opacity Monitors^h

Parameter	EPA Requirements or Recommended State Requirements
Equipment Specifications	
Peak and mean spectral responses	500 nm - 600 nm; response < 400 nm or > 700 nm shall be < 10% of peak (40 CFR Part 60, App. B, PS1, S. 5.1.1)
Angle of view	No greater than 5 degrees (40 CFR Part 60, App. B, PS1, S. 5.1.2)
Angle of projection	No greater than 5 degrees (40 CFR Part 60, App. B, PS1, S. 5.1.3)
Optical alignment sight ^a	Provide method to indicate that unit is misaligned when opacity error is +2% over a path length of 8 m (40 CFR Part 60, App. B, PS1, S. 5.1.4)
Simulated zero and upscale calibration system	Include calibration system that simulates a zero (or no greater than 10%) opacity value to periodically check transmissometer calibration while in operation (40 CFR Part 60, App. B, PS1, S. 5.1.5) ^b
Access to external optics	Provide access to enable cleaning without removing or realigning unit (40 CFR Part 60, App. B, PS1, S. 5.1.6)
Automatic zero compensation indicator ^c	Provide means to indicate when compensation exceeds 4% opacity; indicator must be accessible (40 CFR Part 60, App. B, PS1, S. 5.1.7)
Slotted tube ^c	Length of slotted tube must be $\geq 90\%$ ^d of the effluent path length; size or orientation must not interfere with flow; transmissometer must minimize light reflections (40 CFR Part 60, App. B, PS1, S. 5.1.8)
Data reduction/recording	For Part 51: Data reduction, recording & reporting in accordance with applicable opacity standards. If automatic adjustment to corrected calibration value, must record amount of adjustment. Data recorded during opacity monitor malfunction, repairs, calibrations, and adjustments shall not be used. (App. M, S. 3.2)
External calibration filter access	For Part 60: Recommended provisions to permit use of external neutral density filters for calibration (40 CFR Part 60, App. B, PS1, S. 5.1.9)
Zero & upscale calibration evaluations	For Part 51: Must accommodate use of calibration filter assembly and permit use of external neutral density filters (App. M, S. 3.1) For Part 51: Must include a method for neutral density filters. Provide a check of analyzer option surfaces and all active electronic circuitry including lamp and photodetector assembly used in measurement mode (App. M S. 3.3)

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Table 3-2E
Equipment and Performance Specifications for Opacity Monitors^b (continued)

Parameter	EPA Requirements or Recommended State Requirements
Performance Specifications	
Calibration error ^a	No greater than 3% opacity (40 CFR Part 60, App. B, PS1, S. 5.2, Table 1-1)
Response time	No greater than 10 sec (40 CFR Part 60, App. B, PS1, S. 5.2, Table 1-1)
Conditioning period ^f	No less than 168 hr (40 CFR Part 60, App. B, PS1, S. 5.2, Table 1-1)
Operational test period ^f	168 hr (40 CFR Part 60, App. B, PS1, S. 5.2, Table 1-1)
Zero drift (24 hr) ^e	No greater than 2% opacity (40 CFR Part 60, App. B, PS1, S. 5.2, Table 1-1)
Calibration drift (24 hr) ^a	No greater than 2% opacity (40 CFR Part 60, App. B, PS1, S. 5.2, Table 1-1)
Data recorder resolution	No greater than 0.5% opacity (40 CFR Part 60, App. B, PS1, S. 5.2, Table 1-1)
Instrument span value	For Part 60 Subpart D: 80%, 90%, or 100% (S. 60.45 (c)(3)) For Part 60 Subpart Da: Between 60% and 80% (S. 60.47a (i)(3)) For Part 51, App. P: Approximately 200% of expected output ^g (S. 3.8)
Cycle period	For Part 51, App. P: Cycle of sampling and analyzing no less than 10-sec (App. P, S. 3.4.1) For Part 51, App. M: Cycle of data recording 6-min (75.10(d)(2)) (App. M, S. 3.4)

^a Instruments that provide an absolute zero check while in operation with effluent present and while maintaining the same optical alignment during measurement and calibration are exempt.

^b System must provide, as a minimum, a system check of the analyzer internal optics and all electronic circuitry.

^c If applicable.

^d For length less than or equal to 90% of effluent path length, demonstrate that acceptable results can be obtained.

^e Expressed as the sum of the absolute value of the mean difference and the absolute value of the confidence coefficient.

^f During the conditioning and operational test periods, the monitor must not require any corrective maintenance, repair, replacement, or adjustment, other than that clearly specified as routine and required in the operation and maintenance manuals.

^g Corresponding to the emission standard for the source.

^h Equipment and performance specifications vary between states. This table summarizes the specification required by EPA in 40 CFR Part 75, Part 60 Subpart Da and Part 60 Subpart D, as well as specifications currently proposed by EPA in 40 CFR Part 51 Appendix M Method 203 for state implementation plans.

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Table 3-3A
Recordkeeping Requirements

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§ 60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
Unit Operating Parameters: § 75.50				
Dates and hours	(b)(1)	§ 60.7(c)	§ 60.7(c)	App. P, S. 4.4
Unit operating time	Hourly (b)(2)	Quarterly (§ 60.7)(b) and (d)(2)	Semiannually (§ 60.7)(b) and (d)(2)	Quarterly (App. P, S. 4.4) ^a
Total integrated unit load (MWge)	Hourly (b)(3)	Not Required	Not Required	Not Required
Operating load range	Hourly (b)(4)	Not Required	Not Required	Not Required
Total heat input (MBtu)	Hourly (b)(5) (The total heat input for gas-fired units may be recorded daily)	Not Required	Not Required	Not Required
Certifications, QA & QC Record Provisions for Pollutant and Diluent Monitors: § 75.52				
Daily and 7-Day Calibration Error Tests/Calibration Drift Tests				
Monitor channel ID code	(a)(1)(i)			
Instrument span	(a)(1)(ii)			
Date and hour	(a)(1)(iii)			
Calibration gas reference value	Daily (a)(1)(v)	(App. F, S. 7)		
Monitor response (observed value)	Daily (a)(1)(v)	(App. F, S. 7)	Not Required	Not Required

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Daily and 7-Day Calibration Error Tests/Calibration Drift Tests (continued)</i>			Not Required	Not Required
Concentration monitor calibration error (%)	Daily (a)(1)(vi)	Daily (§ 60.7(d)(2))	Daily (§ 60.7(d)(2))	Daily (App. P, S. 3.7) ^a
Concentration monitor out-of-control hours (hr)	Daily (a)(1)(vii)	Hourly, include explanation and description of repairs and description of repairs (§ 60.7(c)(3))	Daily, include explanation and description of repairs (§ 60.7(c)(3))	Daily, include explanation and description of repairs (App. P, S. 4.4)
Description of corrective actions, maintenance	(a)(1)(viii)			
<i>Linearity Checks/Calibration Gas Audits</i>				
Monitor channel ID code	(a)(3)(i)			
Instrument span	(a)(3)(ii)			
Date and hour	(a)(3)(iii)	(App. F, S. 7)		
Calibration gas reference value	(a)(3)(iv)	(App. F, S. 7)		
Monitor response (observed value)	(a)(3)(v)	(App. F, S. 7)		
Percent error for each gas concentration	(a)(3)(vi)	(App. F, S. 7)		
Number of out-of-control hours	(a)(3)(vii)			
Description of corrective action, maintenance	(a)(3)(viii)			
<i>Relative Accuracy Tests</i>			Not Required	Not Required
Date and hour	(a)(5)(i)	(App. F, S. 7)		
Reference Methods used	(a)(5)(ii)	(App. F, S. 7)		

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Regulatory Comparison

Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Relative Accuracy Tests (continued)</i>			Not Required	Not Required
Individual test run data	(a)(5)(iii)	(App. F, S. 7)		
Calculations and tabulated results	(a)(5)(iv)	(App. F, S. 7)		
SO₂ Parameters				
General Requirements: § 75.50				
Monitor channel ID code	(c)(1)(i)			
Date and hour	(c)(1)(ii)			
Average SO ₂ concentration (ppm)	Hourly (c)(1)(iii)	30-day rolling averages Corrected to lb/MBtu, flag excess emission periods, describe reasons for excess emissions (§ 60.7(c)(1) and (d)(2))	Hourly Corrected to lb/MBtu, flag excess emission periods, describe reasons for excess emissions (§ 60.7(c)(1) and (d)(2))	Hourly Corrected to units of the standard, flag excess emission periods, describe reasons for excess emissions (App. F, S. 4.3)
Average SO ₂ concentration, adjusted for bias (ppm)	Hourly, if required (c)(1)(iv)	Not Required	Not Required	Not Required
SO ₂ concentration monitor availability (%)	Calculated pursuant to § 75.32 (c)(1)(v)	Quarterly (§ 60.7(d)(2))	Semiannually (§ 60.7(d)(1)) Quarterly if total duration of excess emissions is > 1% or total CEM system downtime is > 5% (§ 60.7(d)(2))	Quarterly (App. P, S. 4.4)
SO ₂ method code	(c)(1)(vi)	Hourly, describe alternate method used (b)(7)		

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Table 3-3A

Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
SO₂ Parameters				
General Requirements: § 75.50 (continued)				
SO ₂ mass emission rate (lb/hr)	Hourly (c)(3)(ii)	Not Required	Not Required	Not Required
SO ₂ mass emission rate, adjusted for bias (lb/hr)	Hourly, if required (c)(3)(iii)	Not Required	Not Required	Not Required
SO ₂ mass emissions formula, 3- digit code	(c)(3)(iv)	Not Required	Not Required	Not Required
NO_x Parameters				
General Requirements: § 75.50				
Monitor channel ID code	(d)(1)	Not Required	Not Required	Not Required
Date and hour	(d)(2)	Not Required	Not Required	Not Required
Average NO _x concentration (ppm)	Hourly (d)(3)	Not Required	Not Required	Hourly, corrected to units of the standard, flag excess emission periods, describe reasons for excess emissions (App. P, S, 4.3)
Average diluent concentration (%)	Hourly (d)(4)	Not Required	Not Required	Not Required
Average NO _x emission rate (lb/MBtu)	Hourly (d)(5)	30-day rolling average, flag excess emission periods, describe reasons for excess emissions (§ 60.7(c)(1) and (d)(2))	Hourly, flag excess emission periods, describe reasons for excess emissions (§ 60.7(c)(1) and (d)(2))	Not Required

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
NO_x General Requirements: § 75.50 (continued)				
Average NO _x emission rate, adjusted for bias (lb/MBtu)	Hourly (d)(6)	Not Required	Not Required	Not Required
NO _x CEM system availability (%)	Calculated pursuant to § 75.32 (d)(7)	Quarterly (§ 60.7(d)(2))	Semiannually (§ 60.7(d)(2))	Quarterly (App. P, S. 4.4)
NO _x method code	(d)(8)	Hourly, describe alternate method used (b)(7)	Not Required	Not Required
NO _x emissions formula, 3-digit code	(d)(9)	Not Required	Not Required	Not Required
F-factor values for NO _x emission rate calibrations	(f)(4)	(b)(6)	Not Required	Not Required
Diluent Parameters				
General Requirements: § 75.50				
Monitor channel ID number	(e)(1)(i)	Not Required	Not Required	Not Required
Date and hour	(e)(1)(ii)	Not Required	Not Required	Not Required
Average CO ₂ (O ₂) concentration (%)	Hourly (e)(1)(iii)	Hourly	Not Required	Not Required
Average volumetric flow rate (scfh)	Hourly (e)(1)(iv)	Not Required	Not Required	Not Required
Average CO ₂ mass emissions (tons/hr)	Hourly (e)(1)(v)	Not Required	Not Required	Not Required

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Table 3-3A Recordkeeping Requirements (continued)				
Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
Diluent Parameters				
General Requirements: § 75.50 (continued)				
Diluent monitor availability (%)	Calculated pursuant to § 75.32 (annually) (f)(1)(i)(e)(1)	Quarterly (§ 60.7(d)(2))	Semiannually (§ 60.7(d)(2))	Quarterly (App. P, S. 4.4)
CO ₂ method code	(e)(1)(vii)	Not Required	Not Required	Not Required
CO ₂ emissions formula, 3-digit code	(e)(1)(viii)	Not Required	Not Required	Not Required
Alternative to § 75.50(e)(1) General Requirements - Use § 75.13 and Appendix G				
Date	(e)(2)(i)	Not Required	Not Required	Not Required
Average combustion-formed CO ₂ mass emissions (tons/day)	Daily (e)(2)(ii)	Not Required	Not Required	Not Required
Optional adjustment (coal-fired units only) procedure for combustion-fired CO ₂ mass emissions for carbon retained in fly ash (used or not)	(e)(2)(iii)	Not Required	Not Required	Not Required
Average sorbent-related CO ₂ mass emissions (tons/day)	Daily Wet FGD only (e)(2)(v)			
Average total CO ₂ mass emissions (sum of combustion formed and sorbent-related emissions)	Daily Wet FGD only (e)(2)(v)			

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (\$§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (\$60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
Flow Parameters				
General Requirements:				
§ 75.50				
Monitor channel ID code	(c)(2)(i)			
Date and hour	(c)(2)(ii)			
Average volumetric flow (scfh)	Hourly (c)(2)(iii)			
Average volumetric flow, adjusted for bias (scfh)	Hourly, if required (c)(2)(iv)			
Average moisture content when SO ₂ concentration is measured on a dry basis	Hourly (c)(2)(v)			
Flow monitor availability (%)	Calculated pursuant to § 75.32 (c)(2)(vi)			
Flow monitor method code	(c)(2)(vii)			
Certifications, QA & QC				
Record Provisions for Flow Monitors: § 75.52				
<i>Daily and 7-Day Calibration Error Tests</i>				
Refer to Pollutant Monitor Parameter Requirements	(a)(1)			
Interference check pass/fail code	(a)(2)(i)			

Flow Monitoring Is Not Required By These Regulations

Flow Monitoring Is Not Required By These Regulations

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
Certifications, QA & QC Record Provisions: § 75.52 <i>(continued)</i>				
Flow monitor out-of-control hours (hr)	(a)(2)(ii)			
Descriptions of corrective action, maintenance	(a)(2)(iii)			
Quarterly Leak Checks				
Flow monitor leak check pass/fail code	(a)(4)(i)			
Flow monitor out-of-control hours (hr)	(a)(4)(ii)			
Descriptions of corrective action, maintenance	(a)(4)(iii)			
Relative Accuracy Tests				
Refer to pollutant parameter Requirements	(a)(5)			
Flow monitor bias adjustment factor (if required) at each of three gas velocities	(a)(5)(v)(F)			
Additional Information for Units with Subpart Da or Phase I Qualifying SO₂ Removal Technology				
General Requirements: § 75.51				
<i>Units With Post-Combustion Emission Controls</i>				
Monitor channel ID codes for each SO ₂ -diluent CEM system	(a)(1)(i)			

This Information Is Not Required By These Regulations

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Units With Post-Combustion Emission Controls (continued)</i>				
Date and hour	(a)(1)(ii) Hourly (a)(1)(iii)			
Average inlet SO ₂ emission rate (lb/MBtu)	Hourly, if required (a)(1)(iv)			
Average inlet SO ₂ concentration, adjusted for bias (ppm)	Hourly (a)(1)(v)			
Average outlet SO ₂ emission rate (lb/MBtu)	Hourly, if required (a)(1)(vi)			
Average outlet SO ₂ concentration, adjusted for bias (ppm)	Calculated pursuant to Eq. 8 of § 75.32 for year following initial certification and Eq. 9 of § 75.32 thereafter (a)(1)(vii)			
Inlet and outlet SO ₂ -diluent CEM system percent availability (%)	(a)(1)(viii)			
SO ₂ mass emissions formula	Not Required	Daily, 30-day rolling average (b)(3)		
SO ₂ emission removal by controls (%)	Not Required	Quarterly (e)(1)		
SO ₂ emission removal by fuel pretreatment (%)	Not Required	Quarterly (b)(3)		
Total SO ₂ emission removal (%)				
<i>Units With Combustion and/or Pre-Combustion Emission Controls</i>				
Monitor channel ID codes for each outlet SO ₂ CEM system	(a)(2)(i)			
Date and hour	(a)(2)(ii)			

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (\$60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Units With Combustion and/or Pre-Combustion Emission Controls (continued)</i>				
Average outlet SO ₂ emission rate (lb/MBtu)	Hourly (a)(2)(iii)			
Date of each pretreatment fuel shipment	Not Required	Quarterly (e)(2)		
Name and location of pretreatment facility	Not Required	Quarterly (e)(2)		
<i>Units With Combustion Controls</i>				
Average inlet SO ₂ emission rate (lb/MBtu) determined by coal sampling and analysis procedure	Daily (a)(2)(iv)			
<i>Units With Pre-Combustion Controls</i>				
Weight of raw fuel lots (tons) ^c	(a)(2)(v)	Quarterly (e)(2)		
Weight of product fuel lots (tons) ^c	(a)(2)(v)	Quarterly (e)(2)		
Sulfur content of raw fuel lots (%) ^c	(a)(2)(v)	Not Required		
Sulfur content of product fuel lots (%) ^c	(a)(2)(v)	Not Required		
Gross calorific value of raw fuel lots (Btu/lb) ^c	(a)(2)(v)	Quarterly (e)(2)		
Gross calorific value of product fuel lots (Btu/lb) ^c	(a)(2)(v)	Quarterly (e)(2)		

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>This Information is Not Required by These Regulations</i>				
Specific Parametric Data				
Record Provisions for				
Calculating Substitute				
Emissions Data for Units				
With Add-On Emission				
Controls				
General Recordkeeping				
Requirements: § 75.51				
Units With Add-On SO ₂ Emission				
Controls for Each Hour of Missing				
SO ₂ Concentration Or Volumetric				
Flow Data				
All information required in	(b)(1)(i)			
§ 75.50(b) for SO ₂ concentration				
for flow monitors if either are still				
operating				
Date and hour	(b)(1)(ii)			
Number of scrubber modules in	Hourly			
operation	(b)(1)(iii)			
Feed rate of make-up slurry to each	Hourly			
scrubber module (gal/min)	(b)(1)(iv)			
Average pressure differential	Hourly			
across each operating scrubber	(b)(1)(v)			
module (in H ₂ O)				
For units with wet FGD: in line	Hourly			
measure of absorber pH for each	(b)(1)(vi)			
operating scrubber module (pH				
units)				
For units with dry FGD: inlet and	Hourly			
outlet temperatures across each	(b)(1)(vii)			
scrubber module (° F)				

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (\$60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Units With Add-On SO₂ Emission Controls for Each Hour of Missing SO₂ Concentration Or Volumetric Flow Data (continued)</i>				
Slurry feed rate to atomizer nozzle (gal/min)	Hourly (b)(1)(viii)			
SO ₂ concentration method code	(b)(1)(ix)			
Volumetric flow method code	(b)(1)(ix)			
<i>Units With Add-On NO_x Emission Controls for Each Hour of Missing NO_x Emission Rate Data</i>				
Date and hour	(b)(2)(i)			
Inlet air flow rate (acfh)	Hourly (b)(2)(ii)			
Excess O ₂ concentration of flue gas at stack outlet (%)	Hourly (b)(2)(iii)			
CO concentration of flue gas at stack outlet (ppm)	Hourly (b)(2)(iv)			
Flue gas temperature at furnace exit or economizer outlet duct (° F)	Hourly (b)(2)(v)			
Other parameters specific to NO _x emission controls	Hourly (b)(2)(vi)			
<i>SO₂ Emission Record Provisions for Gas- or Oil-fired Units Using Optional Protocol in Appendix D</i>				
<u>Oil-Fired</u>				
Date and hour	(c)(1)(i)			
Oil flow rate in appropriate measurement units (lb/hr)	Hourly (c)(1)(ii)			

This Information is Not Required by These Regulations

This Information is Not Required by These Regulations

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (\$60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Oil-Fired (continued)</i>				
Daily oil sulfur content (%)	Hourly/Daily (c)(1)(iii)			
Oil sampling method	Hourly (c)(1)(iv)			
Mass of oil combusted (lb/hr)	Hourly (c)(1)(v)			
Average SO ₂ mass emissions (lb/hr)	Hourly (c)(1)(vi)			
Highest sulfur content recorded from the most recent 30-day oil samples (%)	Daily (c)(2)			
<i>Gas-Fired</i>				
Date and hour	(c)(3)(i)			
Heat input from natural gas using App. F, Part 75 procedures (MBtu)	Daily (c)(3)(ii)			
Gas sample sulfur content and volume of gas combusted per day (scf); or	Daily (c)(3)(iii)(A)			
SO ₂ emission rate from NADB (lb/MBtu)	(c)(3)(iii)(B)			
<i>NO_x Emission Record Provisions for Gas- or Oil-Fired Peaking Units Using Optional Protocol in Appendix E, Part 75</i>				
<i>Oil-Fired</i>				
Date and hour	(d)(1)(i)			

This Information is Not Required by These Regulations

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Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<u>Oil-Fired (continued)</u>				
Average fuel flow of oil in appropriate units (i.e., gal/day)	Daily (d)(1)(ii)			
NO _x emission rate F-factor for oil combusted (App. E, Part 75)	(d)(1)(iii)			
Average NO _x emission rate (lb/MBtu)	Daily (d)(1)(iv)			
<u>Gas-Fired</u>				
Date and hour	(d)(2)(i)			
Average fuel flow of natural gas (ft ³)	Daily (d)(2)(ii)			
NO _x emission rate F-factor for gas combusted (App. E, Part 75)	(d)(2)(iii)			
Average NO _x emission rate (lb/MBtu)	Daily (d)(1)(iv)			
Additional Information Required if SO₂ Standards are Exceeded Because of Control System Malfunction				
Time period of emergency condition	Not Required	For applicable 30-day period (d)(2)(i)		
Electrical output and system/facility demand	Not Required	For applicable 30-day period (d)(2)(ii)		

This Information Is Not Required For These Regulations

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Regulatory Comparison

Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (\$60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>This Information Is Not Required For These Regulations</i>				
Additional Information Required if SO₂ Standards are Exceeded Because of Control System Malfunction (continued)				
Amount of power purchased during emergency period	Not Required	For applicable 30-day period (d)(2)(iii)		
Percent in emissions (%)	Not Required	For applicable 30-day period (d)(2)(iv)		
SO ₂ emission rate (lb/MBtu)	Not Required	For applicable 30-day period (d)(2)(v)		
Actions taken to correct malfunction	Not Required	For applicable 30-day period (d)(2)(vi)		
<i>This Information Is Not Required For These Regulations</i>				
Additional Information Required if Minimum Quantity of Emission Data Points is Not Obtained				
Number of hourly averages available for outlet emission rates	Not Required	For applicable 30-day period (c)(1)		
Number of hourly averages available for inlet emission rates	Not Required	For applicable 30-day period (c)(1)		
Standard deviation of hourly averages for outlet emission rates	Not Required	For applicable 30-day period (c)(2)		

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Table 3-3A

Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
<i>This Information Is Not Required For These Regulations</i>				
Additional Information Required if Minimum Quantity of Emission Data Points is Not Obtained (continued)				
Standard deviation of hourly averages for inlet emission rates	Not Required	For applicable 30-day period (c)(2)		
Lower confidence limit for mean outlet emission rate	Not Required	For applicable 30-day period (c)(3)		
Upper confidence limit for mean inlet emission rate	Not Required	For applicable 30-day period (c)(3)		
Applicable potential combustion concentration (%)	Not Required	For applicable 30-day period (c)(4)		
Ratio of upper confidence limits for mean outlet emission rate and allowable emission rate	Not Required	For applicable 30-day period (c)(5)		
Other Required Information				
QA Reports	See Table 1E	See Table 1E	Not Required	Not Required
Periods when emissions exceed instrument span	Not specified	Daily (b)(8)	Not Required	Not Required
Description of changes since last report period	Not Required	Quarterly (§ 60.7(c)(3))	Quarterly (§ 60.7(c)(3))	Not Required

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Regulatory Comparison

Table 3-3A
Recordkeeping Requirements (continued)

Information/Data	40 CFR Part 75 Subpart F (§§ 75.50 - 75.52)	40 CFR Part 60 Subpart Da (§60.49a)	40 CFR part 60 Subpart D	40 CFR Part 51 Appendix P
Other Required Information (continued)				
Excess emissions resulting from start up, shut-down, and malfunction of boiler or control equipment	Not Required	Quarterly, including description and duration of event (§ 60.7(b) and (c)(2))	Quarterly, including description and duration of event (§ 60.7(b) and (c)(2))	Not Required
Initial performance certification and CEM maintenance records ^a	3 years Subpart F § 75.50(a)	2 years (§ 60.7(e))	2 years (§ 60.7(e))	2 years (App. P, S. 4.6)
Written record describing procedures used to implement recordkeeping and reporting requirements of Subparts F and G	App. B, S. 1.5	Not Required	Not Required	Not Required
QA/QC Program Plans ^a	Written QAP required Annual review (i)	Written QAP required Review each time identical problems occur in 2 consecutive quarters (App. F, S. 3)	Written calibration procedures required (§ 60.13 (d)(1))	Not Required
Signed statements certifying that all procedures have been followed properly and all information is accurate	Not Required	Quarterly (§ 60.49a(g))	Not Required	Not Required

^a Recordkeeping requirement only, not a reporting requirement.

^b Daily results must be reported for the initial 30-day test quarterly, and annual results must be reported thereafter until December 31, 1999.

^c Typical units - units not specified by regulations.

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Table 3-3B
Recordkeeping for Opacity Monitors

Information/Data	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix M ^a
General Information				
§ 75.50				
Monitor-channel ID code	(f) (1)			
Date, hour, & minute	(f) (1)			
Average opacity of emissions in % opacity	(f) (1)			
Code indicating exceedance, if occurred	(f) (1)			
Percent monitor data availability	(f) (1)			
Monitoring Plan § 75.53				
Identification of certification test strategy	(1)			
Description of monitoring site location	(3)			
Manufacturer model and serial numbers	(4) (i)			
Monitor-channel ID code	(4) (ii)			
Actual/Projected date of installation	(4) (iii)			
Method of operation	(4) (iv)			
Designation as primary or backup	(4) (vi)			
Results of assessments				
Corrective maintenance & adjustments				

This Information is Not Required by These Regulations^b

^a EPA Proposed Method 203.

^b Specific recordkeeping requirements are not provided in 40 CFR Part 60 or Part 51; however, Part 60 (S. 60.7) does require that all owners or operators subject to monitoring requirements in Part 60 shall maintain a file of all CEM/opacity monitoring measurements, performance test measurements and results, records of adjustments and maintenance, and other relevant or required information. Additional state recordkeeping requirements may also apply.

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Regulatory Comparison

Table 3-4A
Reporting Requirements - Submittal Date/Frequency

Required Report(s)	40 CFR Part 75 Subpart G (§§ 75.60 - 75.64)	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart Da	40 CFR Part 51 Appendix P
Monitoring Plan	Submittal ≤ 45 days prior to certification testing (§ 75.62(a))	Not Required	Not Required	Not Required
Certification/Recertification applications	≤ 30 days after completion of testing (§ 75.63(a))	Initially: Performance Evaluation Report (§ 60.49a(a)). Within 60 days of performing the CEM performance tests (§ 60.13(c)(2))	Initially: Performance Evaluation Report (§ 60.45(c)). Within 60 days of performing the CEM performance tests (§ 60.13(c)(2))	Not Required
Summary Reports	Not Required	Quarterly (§ 60.7(c))	Semiannually (§ 60.7(c))	Not Required
Electronic Quarterly Reports	Submittal ≤ 30 days from the end of each calendar quarter beginning with the data from the later of: the last (partial) calendar quarter of 1993 (where the calendar quarter data begins Nov. 15, 1993) or the calendar quarter corresponding to the relevant deadline for certification in § 75.4 of this part (§ 75.64(a))	Not Required	Not Required	Not Required
Electronic Quarterly Reports Include:		Not Required	Not Required	Not Required
Information and hourly data required in §§ 75.50 - 75.52 excluding description of corrective action, adjustments, or maintenance	§ 75.64(a)(1) See Quarterly Electronic Data Reporting Requirements (Version 1.1)			

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EPRI Licensed Material

Table 3-4A
Reporting Requirements - Submittal Date/Frequency (continued)

Required Report(s)	40 CFR Part 75 Subpart G (§§ 75.60 - 75.64)	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Electronic Quarterly Reports Include (continued):</i>				
Tons of SO ₂ emitted	Quarterly: § 75.64(a)(2) Cumulative year-to-date total: § 75.64(a)(2)	Not Required	Not Required	Not Required
Average NO _x emission rate (lb/MBtu)	Quarterly: § 75.64(a)(3) Cumulative year-to-date total: § 75.64(a)(93)			
Tons of CO ₂ emitted (tons)	Quarterly: § 75.64(a)(4) Cumulative year-to-date total: § 75.64(a)(4)			
Total heat input (MBtu)	Quarterly: § 75.64(a)(5) Cumulative year-to-date total: § 75.64(a)(5)			
Total integrated gross unit load (MWge)	Quarterly: § 75.64(a)(5) Cumulative year-to-date total: § 75.64(a)(5)			
<i>Other Reporting Requirements</i>				
Compliance certification supporting emission monitoring report	Quarterly: Quality Assurance & Quality Control Test Report; alternative monitoring method speci- fications (if used); corrective actions taken for missing data periods § 75.64(c)	Quarterly: Data Assessment Report (DAR) (App. F, S. 7)	Semiannually: Monitoring System Performance Report (§ 60.7(c)) ^b	Not Required

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Regulatory Comparison

Table 3-4A
Reporting Requirements - Submittal Date/Frequency (continued)

Required Report(s)	40 CFR Part 75 Subpart G (§§ 75.60 - 75.64)	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
<i>Other Reporting Requirements (continued):</i>				
Phase I Qualifying Technology reports	First Report Only: Acceptance Test result indicating the system's potential to meet 90% reduction efficiency requirement All Reports: All measurements and calculations substantiating that the qualifying technology achieves the overall percent reduction in SO ₂ emissions § 75.64(e)	Not Applicable Not Applicable	Not Applicable Not Applicable	Not Applicable Not Applicable
Alternative Flow Monitor Location Demonstration reports	§ 75.66(a) Subpart G			
Alternative ASTM Method Demonstration reports	§ 75.66(b) Subpart G			
Alternative Monitoring System Petition	§ 75.66(c) Subpart G			
Parametric Monitoring Procedure Petition	§ 75.66(d) Subpart G			
Missing Data Petition for units with add-on emission controls	§ 75.66(e) Subpart G			
Petition for Exemption from Part 75 requirements for units retiring prior to January 1, 1995	On or before Dec. 31, 1994 (§§ 75.67 & 75.4)			

^a If Subpart D CEM system data are used for compliance by the cognizant state agency, QA requirements under Subpart Da/Appendix F may be applicable (§ 60.13(a)).

^b Not required if periods of excess emissions < 1% of operating time and CEM system downtime < 5% of operating time (§ 60.7(d)(1)).

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Table 3-4B
Quarterly CEM System Quality Assurance Reporting Requirements^a

Item	Information Required	40 CFR Part 75 Appendix B	40 CFR Part 60 Subpart Da (App. F, S. 7)	40 CFR Part 60 Subpart D (§ 60.7 and § 60.45(g))
1	Description of Monitor Locations	Not required	Required	Not required
2	CEM Manufacturers and Model Numbers	Not required	Required	Not required
3	Description of Tests Performed	Required (including dates)	Not required	Not required
4	CEM Audit Results (scheduled and unscheduled)	Two-point CE Tests Three-point LE Tests One-Level RATAs Three-Level RATAs Bias Tests Indicating Low Bias Bias Adjustment Factors Leak Checks (Flow Analyzers)	CD Tests CGAs RAAs RATAs	Not required
5	CEM Data Obtained During QA Audits	Required ^b	Required	Not required
6	Reference Method (RM) Data Obtained During QA Audits	Individual test runs ^b and supporting field data	RM test results, only	Not required
7	Calculations	All statistical calculations and comparisons with CEM data ^b	Not required	Not required
8	Identification of Out-of-Control Periods	Required	Required	Required
9	Description of Corrective Action	Required	Required	Required
10	Reference Cylinder Gas Values	Required for all linearity checks (3-point tests)	Required	Required
11	Submittal of Quarterly QA Report	Within 30 days following end of each calendar quarter	By 30th of month following end of each calendar quarter	By 30th of month following end of each calendar quarter
12	Maintenance of QA Records by Owner/Operator	3 years	2 years	2 years ^c

^a 40 CFR Part 51 does not specify quality assurance reporting requirements; however, some specific state requirements may apply.

^b Each quarterly report shall be submitted to Administrator in a specified format (See the QA/QC test file record structure in EPA's Electronic DATA Reporting Requirements Version 1.1).

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Table 3-4C
Required Opacity Reports

Report/Information	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51
Excess Emission Report	Quarterly - Report excess emissions to state and local agencies in required format (§ 75.53)	Quarterly § 60.45 (g)	Quarterly § 60.49a (h)	Quarterly (App. P, S.4.1)
Data Assessment Report (DAR), including Source owner, operator's name and address, monitor's serial number, location of each monitor, manufacturer & model number, results of opacity monitor performance assessments, QA/QC audits, and a summary of all corrective actions.		Not required	Not required	Quarterly (App. M, S.7) ^a

^a Submit to state if required by SIP.

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EPRI Licensed Material

Table 3-5
Notification Requirements

Notification Requirement	40 CFR Part 75	40 CFR Part 60 Subpart Da	40 CFR Part 60 Subpart D	40 CFR Part 51 Appendix P
Commencement of construction or reconstruction (as per § 60.15)	Not Required	Postmarked within 30 days (§ 60.7(a)(1))	Postmarked within 30 days (§ 60.7(a)(1))	Not Required
Anticipated initial startup of an affected facility	Not Required	Postmarked 30 to 60 days prior to startup (§ 60.7(a)(2))	Postmarked 30 to 60 days prior to startup (§ 60.7(a)(2))	Not Required
Actual initial startup of an affected facility	Not Required	Postmarked within 15 days after startup (§ 60.7(a)(3))	Postmarked within 15 days after startup (§ 60.7(a)(3))	Not Required
Changes to a facility that increase emission rate	Not Required	Postmarked at least 60 days prior to the change (or as early as practical) (§ 60.7(a)(4))	Postmarked at least 60 days prior to the change (or as early as practical) (§ 60.7(a)(4))	Not Required
Certification/Recertification Test Notifications for each CEM system	≤ 45 days prior to first day of testing (§ 75.61(a))	≤ 30 days prior to first day of testing (§ 60.7(a)(5))	≤ 30 days prior to first day of testing (§ 60.7(a)(5))	Not Required
Proposed adjustments to test dates	≤ 7 business days prior to adjustment (§ 75.61(a)(1))	Not Required	Not Required	Not Required

Appendix B: Status of State Title V Operating Permit Programs

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PERMITS AND LICENSES

Status of State Operating Permit Programs

POLICY GUIDE

The following chart, which reflects the status of state and local agency air operating permit programs, was derived from national Title V operating permit surveys of program submittals conducted by the Environmental Protection Agency. The information on the chart is subject to change as EPA acts on program submittals.

Under Title V of the 1990 Clean Air Act amendments, state or local agencies were to have submitted to EPA by Nov. 15, 1994, an operating permit program. After a program is submitted, EPA must determine whether it is complete for processing. If determined incomplete, the program must be resubmitted and must undergo another completeness determination. Once determined complete, the agency has one year to approve or disapprove the program. In the interim, EPA also must publish a proposed approval or disapproval in the *Federal Register*. Final action on program submittals also must appear in the *Register*. After final approval is given to a program, sources may have up to one year to submit applications. However, some state and local agencies with more stringent programs may require applications sooner.

Under the Air Act, if a state failed to submit a program by May 15, 1995, EPA must impose sanctions and implement a federal operating permit program (see p. 111:251 for more information on sanctions).

Details of the Air Act's operating permit program may be found beginning on p. 131:51.

STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
ALABAMA** (State and local submittals: Huntsville, Jefferson)	Proposed interim approval Sept. 13, 1995 (60 FR 47522)	\$25/ton+cpi***	Actual
ALASKA	Program resubmitted June 5, 1995. No completeness determination.	\$20	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
ARIZONA (State and local submittals: Pinal-Gila, Pima, Maricopa)	Proposed interim approval July 13, 1995 (60 FR 36083)	\$33+cpi***	Actual
ARKANSAS	Final interim approval Sept. 8, 1995 (60 FR 46771)	\$25+cpi***	Allowable
CALIFORNIA	See p. 111:1741		
COLORADO	Final interim approval Jan. 24, 1995 (60 FR 4563)	\$10.98	Actual
CONNECTICUT	Program submitted Sept. 28, 1995. No completion determination made.	\$25	Actual
DELAWARE	Proposed interim approval Sept. 21, 1995 (60 FR 48944)	\$25+cpi***	Actual
DISTRICT OF COLUMBIA	Final interim approval Aug. 7, 1995 (60 FR 40101)	\$25+cpi***	Actual
FLORIDA	Final interim approval Sept. 25, 1995 (60 FR 49343)	\$10-1993, 1994; \$25-1995; \$35 cap thereafter	Actual or Allowable
GEORGIA	Proposed interim approval Sept. 26, 1995 (60 FR 49533)	\$25+cpi***	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
HAWAII	Final interim approval Dec. 1, 1994 (59 FR 61549)	\$37	Actual
IDAHO	Proposed disapproval Oct. 27, 1995. However, if deficiencies are corrected before final rulemaking as expected, EPA will change the action to proposed interim approval (60 FR 54990)	\$30	Allowable or actual if no previous permit has been issued
ILLINOIS	Final interim approval March 7, 1995 (60 FR 12478)	\$13.50	Allowable
INDIANA	Proposed interim approval May 22, 1995 (60 FR 27064)	\$25+cpi***	Actual
IOWA**	Final interim approval Sept. 1, 1995 (60 FR 45671)	\$24	Actual
KANSAS	Proposed full approval July 3, 1995 (60 FR 34493)	\$18	Actual
KENTUCKY (State and local submittals: Louisville-Jefferson)	Proposed interim approval Sept. 5, 1995 (60 FR 46072)	\$31.08-1995; \$31.52-1996	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
LOUISIANA	Final full approval Sept. 12, 1995 (60 FR 47296)	\$9	Actual.
MAINE	No submittal as of Oct. 30, 1995	Less than \$25	Allowable
MARYLAND	Proposed interim approval Oct. 30, 1995 (60 FR 55231)	\$15-1993; \$18-1995; \$20-1996; \$25-1997 and thereafter	Actual
MASSACHUSETTS	Program submitted April 28, 1995. No completeness determination	\$31.50	Actual
MICHIGAN	Program resubmitted July 20, 1995. No completeness determination	\$6 (interim)	Actual
MINNESOTA**	Final interim approval June 16, 1995 (60 FR 31637) Effective July 17, 1995	\$25+cpi***	Actual or Allowable
MISSISSIPPI	Full approval Dec. 28, 1994 (59 FR 66737)	\$23.39	Actual or Allowable
MISSOURI	Submittal complete Jan. 13, 1995	\$25+cpi***	Actual
MONTANA	Final interim approval May 11, 1995. (60 FR 25143) Effective June 12, 1995	Particulates, Sulfur Dioxide, & Lead: \$11.75 per ton Nitrogen Oxides & VOCs: \$2.94 per ton	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
NEBRASKA (State)	Full approval Oct. 18, 1995 (60 FR)	\$25+cpi***	Actual
NEBRASKA (Lincoln-Lancaster)	Full approval Oct. 18, 1995 (60 FR 53872)	\$25+cpi***	Actual
NEBRASKA (Omaha-Douglas)	Full approval Oct. 30, 1995 (60 FR)	\$25+cpi***	Actual
NEVADA (State)	Proposed interim approval Aug. 7, 1995 (60 FR 40140)	\$3.36 (plus annual maintenance fees per permitted source)	Actual
NEVADA (Clark)	Final interim approval July 13, 1995 (60 FR 36070)	\$33.16+cpi in 1997***	Actual
NEVADA (Washoe)	Final interim approval Jan. 5, 1995 (60 FR 1741)	\$54.79	Actual
NEW HAMPSHIRE	No submittal as of Oct. 30, 1995	\$25	Actual
NEW JERSEY**	No determination. Resubmitted August 21, 1995	\$25+cpi***	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
NEW MEXICO	Final interim approval Nov. 18, 1994 (59 FR 59656), except in Bernalillo County and Indian Lands	\$10.25	Allowable
NEW MEXICO (Albuquerque)	Final Interim Approval (60 FR 2527) Jan. 10, 1995, Effective March 13, 1995	\$22.00 Criteria pollutants, \$250 for 189 HAPs (see p. 100:451.)	Allowable
NEW YORK	Submittal determined incomplete Feb. 2, 1994	less than \$25	Actual
NORTH CAROLINA (State and Western)	Proposed interim approval Aug. 29, 1995 (60 FR 44805)	\$14+cpi+other fees=\$25 in aggregate	Actual
NORTH CAROLINA (Mecklenburg)	Proposed interim approval Aug. 29, 1995 (60 FR 44805)	\$25+cpi*** (+\$5,000 base \$3,500 annual)	Actual
NORTH CAROLINA (Forsyth)	Proposed interim approval Aug. 29, 1995 (60 FR 44805)	>\$25	Actual
NORTH DAKOTA	Final interim approval July 7, 1995 (60 FR 35335)	\$10 per ton with a cap of \$100,000 per source	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
OHIO	Final full approval Aug. 15, 1995 (60 FR 42045)	\$25+cpi***	Actual
OKLAHOMA	Interim approval proposed March 10, 1995 (60 FR 13088)	\$25+cpi***	Actual or Allowable (permittee's discretion)
OREGON (State and local submittal: Lane Regional)	Direct final rule Sept. 28, 1995 (60 FR 50106)	\$25+cpi***	Actual or Allowable.
PENNSYLVANIA	Program resubmitted May 15, 1995	\$37+cpi***	Actual
PENNSYLVANIA (Allegheny, Philadelphia)	No submittals as of Oct. 30, 1995	\$37+cpi***	Actual
RHODE ISLAND	Program submitted June 20, 1995. No completeness determination	\$25+cpi***	Allowable
SOUTH CAROLINA	Final full approval June 26, 1995 (60 FR 32913)	\$25+cpi***	Actual
SOUTH DAKOTA	Proposed full approval Sept. 21, 1995 (60 FR 48942)	Annual Administrative Fees: less than 50 tpy - \$500 more than 100 tpy - \$1,000 Rock crushers - \$250 (flat fee)	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
TENNESSEE** (State and local submittals: Hamilton)	Program submitted June 26, 1995. No completeness determination	\$25+cpi*** \$16.25	Actual Allowable
TENNESSEE** (Nashville-Davidson)	Proposed full approval or proposed interim approval Oct. 11, 1995 (60 FR 52890), if changes not adopted prior to final rulemaking	\$25+cpi*** \$16.25	Actual Allowable
TENNESSEE** (Knox)	Completeness determination made July 11, 1994, after resubmittal	\$25+cpi*** \$16.25	Actual Allowable
TENNESSEE** (Shelby)	Program submitted June 26, 1995. No completeness determination	\$25+cpi*** \$16.25	Actual Allowable
TEXAS**	Source category-limited interim approval proposed June 7, 1995 (60 FR 30037)	\$25+cpi***	Actual or Allowable
UTAH	Final full approval June 8, 1995 (60 FR 30192) Effective July 10, 1995	\$22	Actual

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STATE	Status	Estimation of Total Fees (per ton of emissions)*	Fee Basis (actual or allowable emissions)
VERMONT	Program submitted April 28, 1995	\$30	Actual
VIRGINIA	Proposed disapproval Sept. 19, 1995 (60 FR 48435)	\$25+cpi***	Actual
WASHINGTON (State and local submittals: Energy Facility Site Evaluation Council, Benton Franklin, Northwest, Olympic, Puget Sound, Spokane, Southwest, Yakima)	Interim program approvals Nov. 9, 1994 (59 FR 55813)	NWAPA; \$19.29 SWAPCA; \$19.13 state and others; \$40--\$64.72	Actual
WEST VIRGINIA	Proposed interim approval Aug. 29, 1995 (60 FR 44799)	\$15-1994 \$18-1995	Actual
WISCONSIN	Final interim approval March 6, 1995, effective April 5, 1995 (60 FR 12128)	\$30.18	Actual
WYOMING	Final interim approval Jan. 19, 1995 (60 FR 3766); effective Feb. 21, 1995	\$10	Actual

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In addition to required emissions fees, the following states and localities impose air toxics fees: Colorado (\$75/ton); Connecticut (possible general fee); Idaho (\$5/curie for DOE sites); Louisiana (\$25/\$50/\$100, depending on classification of toxic); Maine (has authority for air toxics surcharge beginning November 1994, but legislation requires study to look at alternatives to toxics surcharge); New Mexico (\$150/ton+cpi); and North Dakota (\$25/ton).

**State seeks interim approval. Under the permit rule (40 CFR 70), EPA may give a state operating permit program interim approval for up to two years if the program elements "substantially meet the requirements of Title V." Interim permits have the full standing of complete-program permits.

***CPI refers to the consumer price index. The Air Act set a presumptive minimum emissions fee of \$25 per ton that must be adjusted annually according to fluctuations in the CPI. If states do not adopt the presumptive minimum, they must demonstrate that lesser fees are adequate to fund their operating permit programs. As of February 1995, the CPI is \$30.07.

Appendix C: Continuous Emission Monitoring Technologies

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CONTINUOUS EMISSION MONITORING TECHNOLOGIES

Keeping pace with increasingly stringent regulations, CEM technology has become more sophisticated and more reliable.

Over the past 10 years, availability of more reliable CEM instruments, equipped with improved analytical techniques and enhanced electronics, has increased significantly. The demand for new types of monitors (e.g., flow and moisture monitors) and extremely reliable CEM equipment has also increased to meet new monitoring requirements specified by 40 CFR Part 75 regulations and by many states. This section summarizes information on the types of sampling systems available for gaseous emissions, flow, opacity, and moisture and presents an overview of their analytical techniques and principles of operation. Commercially available equipment, recent technological advances, and advantages and limitations associated with each technology are discussed. Emerging technologies for gas, flow, and opacity measurements are briefly described. The functional requirements for data acquisition systems (DASs) and CEM system controllers, and available data management software and hardware, are also presented in this section. A partial list of vendors (current as of the date of this Guidelines Manual) that provide CEM components or systems to the utility industry is presented in Appendix J of this Guidelines Manual. Continually updated information on providers of CEM system equipment and services is available to EPRI members through the EPRINET Emissions Monitoring Forum.

SECTION 5

EPRI Licensed Material

The choice of dilution-extractive, extractive, or in-situ gas sampling techniques is application specific.

Dilution-extractive systems eliminate condensation by sample gas dilution.

SAMPLING SYSTEMS

CEM systems incorporate one of three sampling techniques: dilution-extractive, extractive (i.e., sampling without dilution of the sample gas), and in-situ. Inherent differences exist among the three sampling techniques, and thus each system has distinct strengths and weaknesses, which must be carefully evaluated when selecting an appropriate system for a specific application. The following sections address the principle of operation for commercially available equipment, technological advancements, and advantages and limitations for each sampling system type.

Dilution-Extractive Systems

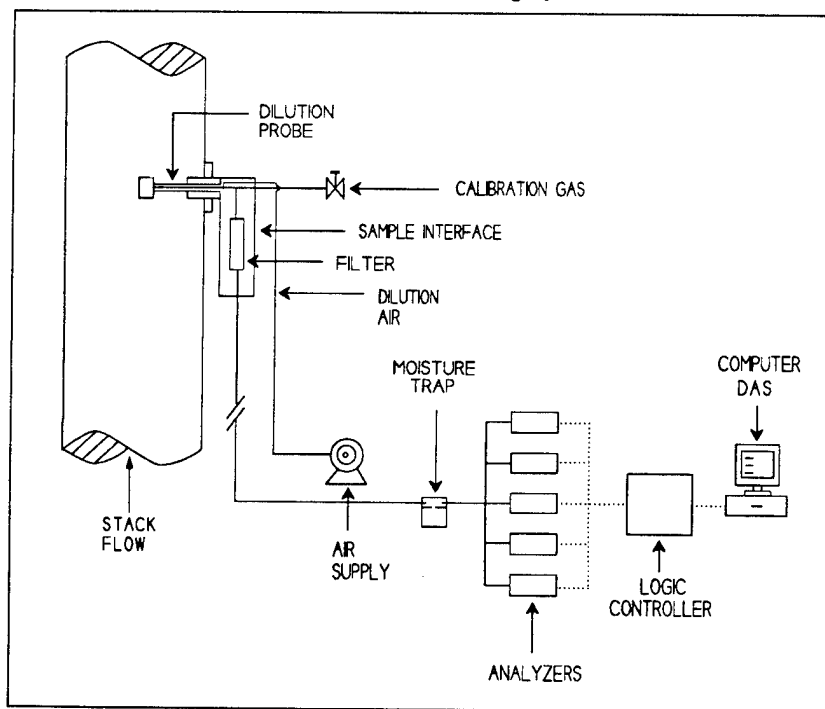
Commercially Available Equipment

Dilution-extractive systems are extractive systems that dilute the sample gas with large quantities of conditioned air to eliminate condensation problems in the CEM system (in lieu of using a moisture condenser). The diluted sample is analyzed by pollutant and CO₂ monitors operating at or near ambient concentration ranges.

A schematic of a typical dilution-extractive system is shown in Figure 5-1. The most unique component of a dilution-extractive system (relative to other extractive systems) is the dilution sampling probe. There are two basic types of dilution probes, in-stack and out-of-stack. The in-stack probe design is equipped with coarse and fine filters for removing particulate matter from the stack gas prior to sample dilution, a quartz or glass critical orifice for flow regulation, and an aspirator and Venturi for dilution of the sample gas.

Figure 5-1

Typical dilution-extractive emission monitoring system.



Dilution is accomplished with specially designed probes.

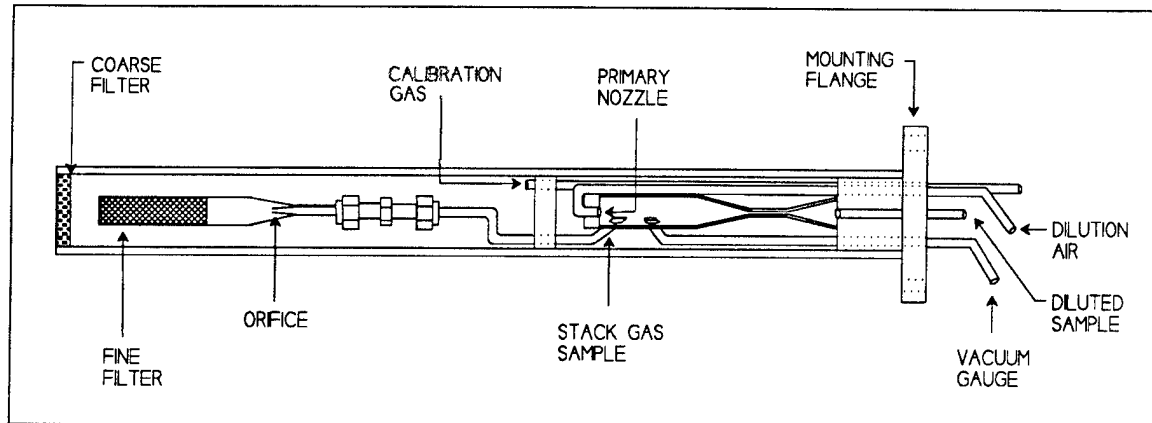
Sample gas dilution typically occurs at stack conditions by applying a specially designed probe (shown in Figure 5-2) that uses the air-driven aspirator and Venturi to collect a filtered gas sample. The sample is then diluted with clean dry air from the aspirator. Dilution ratios typically range from 50:1 to

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250:1, with sample gas flow rates from 50 to 150 ml/min. Two criteria are used to determine the desired dilution ratio: (1) the analyzer range must correspond to the diluted sample gas concentration, and (2) the ratio must be selected to ensure that no condensation develops in the sample line at the lowest possible ambient temperature.

Figure 5-2
Dilution probe tip.



Dilution system sample line bundles typically are not heated.

Diluted sample gas, exiting the air-driven aspirator and Venturi under positive pressure, passes through a sample line to the monitor enclosure. Sample line bundles used with dilution-extractive systems typically are not heated, except when condensation is possible at the calculated dilution ratio and as a protection against freezing in colder climates. The bundles usually consist of four to six separate lines – one Teflon line for sampling, a second Teflon line to deliver calibration and purge gases to the probe, a third line to deliver dilution air to the probe, sometimes a fourth line to monitor vacuum in the probe, and sometimes one or two "spare" Teflon lines. The spare lines are often used for diagnostic purposes (e.g., resolving or isolating leak problems) or for backup monitoring equipment. The diluted gas sample line should be at least 3/8 in. in diameter and, if the overall sample line length exceeds approximately 350 feet, a 1/2-in. sample line may be needed to reduce the pressure drop between the probe and the monitors. High pressure drops may prevent adequate sample flow to the monitors or cause condensation problems. Using a 1/2-in. sample line over long distances, however, can significantly impact response times (response times for a 3/8-in. line are typically 15 seconds for every 100 feet) such that timesharing a CEM system between two locations may be precluded.

Filters and moisture-removal devices eliminate particulates and water droplets.

As a precautionary measure before it enters a sample gas manifold, and subsequently the monitors, the diluted sample gas may be passed through a fine filter and moisture knock-out device to remove any particulate matter and water droplets (not water vapor), respectively. Most dilution-extractive systems measure pollutant and diluent concentrations on a wet basis. Typical ranges for an SO₂, NO_x, and CO₂ monitor are 0-2000 ppb, 0-4000 ppb, and 0-1000 ppm, respectively.

Although sample gas conditioners for moisture removal typically are not used with dilution systems, the dilution air must be conditioned to remove moisture, oil, particulate matter, SO₂, NO_x, and CO₂. Dilution air conditioners typically consist of a permeation dryer, a desiccant dryer, and SO₂, NO_x, and CO₂ scrubbers, followed by a particulate matter filter.

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Critical orifices, improved construction materials, and better probe designs are among recent advances in dilution-extractive technology.

Recent Technological Advances

Dilution system reliability has increased due to the use of critical orifices for controlling flow rates, improved construction materials (Inconel, Hastelloy, etc.), improved probe designs (e.g., probe heat exchangers that compensate for varying gas temperatures), automated purging and calibration, improved diagnostic equipment/procedures, and the use of freeze-protected sample lines.

At least three out-of-stack dilution probes exist that house the filter, inertial separator, orifices, and aspirator system outside of the stack or duct environment in a temperature controlled chamber. In another dilution-extractive system, sample dilution is accomplished just before the monitors and after the gas passes through a particulate matter and moisture removal system (i.e., the monitors measure concentrations on a diluted dry basis). Housing the filter and dilution components outside of the stack facilitates their maintenance because the probe does not have to be removed. These systems can tolerate a wider change in effluent temperatures, and the out-of-stack filter can be fabricated from materials with lower temperature ratings. Potential disadvantages of the out-of-stack dilution probe include (1) the flue gas flow rate through the probe and inertial separator is typically 50 to 200 times greater, and (2) evaluating the need for maintenance can be more difficult with some out-of-stack filter designs.

Dilution-extractive system installation is relatively inexpensive, but stable sampling temperatures are required.

Advantages and Limitations

Dilution-extractive systems offer several advantages. Because the system extracts the sample at a low flow rate, there is less tendency to draw particulate matter into the probe and "fine" filter. The sample transport system lacks moving parts and, therefore, is relatively simple and inexpensive to maintain. Dilution-extractive systems are relatively inexpensive to install and require no heated sample line (although freeze protected line is often used and recommended). Dilution-extractive CEM systems use monitors that would be familiar to personnel currently using ambient air monitors. Most dilution-extractive systems measure pollutant and CO₂ concentrations on a wet basis, which is an advantage when measuring SO₂ or CO₂ mass emissions in lb/hr or tons/yr, respectively. Flow monitors measure volumetric flow on a wet basis and, consequently, a moisture monitor would have to be incorporated in order to produce SO₂, CO₂, and flow measurements on the same moisture basis if the pollutant and CO₂ monitors operate on a dry basis. In addition, dilution-extractive systems have proven to be extremely reliable in many utility applications.

One limitation of dilution-extractive systems is that relatively stable sampling temperatures are needed to maintain constant dilution ratios. Most systems, however, currently offer some method of preheating dilution air and/or the sampling probe to compensate for changing dilution temperatures. In addition, some systems can incorporate an automated calibration procedure that is initiated if effluent temperatures fluctuate significantly. Another difficulty arises when extremely wet effluent streams are sampled. Water droplets can enter the dilution probe and affect sample moisture concentrations as well as cause sample line condensation problems. Several companies offer a demister unit that removes excess water from the sample gas prior to entering the probe, which alleviates this potential problem.

Other limitations of these systems include the following: (1) dilution probe critical orifices can be susceptible to plugging in the presence of "sticky" particulate matter; (2) dilution systems require the use of CO₂ monitors, rather than O₂ monitors (which tend to be more reliable – less troublesome to maintain); (3) dilution ratios should be adjusted for temperature and pressure differentials within the probe and the stack; and (4) calibrations are performed on a dry basis (i.e., no moisture is present in the calibration gas). Some analyzer technologies are prone to moisture interference (e.g., non-dispersive

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infrared CO₂ analyzers), and when the CEM system is calibrated with a dry gas, such interferences are not detectable.

Extractive Systems

Extractive systems remove samples directly from the stack without dilution and, after conditioning, transport samples to gas analyzers.

Commercially Available Equipment

Extractive CEM systems remove effluent gas samples from the exhaust stack or duct. Because extracted samples must be relatively clean and typically dry before being introduced to the analyzers, extractive monitoring systems have a sample conditioning system that removes particulate matter and (in most cases) moisture. Note that some "hot, wet" extractive systems are available. After conditioning, the sample is transported to the system's analyzer(s). First-generation extractive CEM systems were essentially ambient air analyzers, modified to sample and analyze combustion exhaust gases. The early designs often required adding a dilution system to reduce the pollutant concentration to the operating range of the analyzer. Not surprisingly, significant operational problems occurred with these systems. Design improvements of newer extractive monitors, however, now enable the instruments to withstand the challenges of sampling flue gas streams that may contain high concentrations of pollutants, particulate matter, corrosive gases, or moisture.

Extractive systems have four common subsystems: (1) effluent/CEM system interface, (2) sample transport, (3) sample conditioning, and (4) pollutant and diluent analyzers. Some designs combine the sample transport and conditioning systems into an overall sample handling system. A schematic of a typical extractive system is shown in Figure 5-3.

Effluent/CEM system interface. The effluent/CEM system interface typically consists of a rigid probe, positioned at a representative location in the effluent. A variety of coarse filtration media, usually located at the probe inlet, is used to remove particulate matter from the gas sample.

Sample transport system. The sample transport system begins at the junction between the probe and the sample transport line, usually positioned just outside the stack or duct. Sample transport systems consist of sample transport lines (heated in most systems) and a mechanism such as a pump to move the gas sample.

Sample conditioning is most often accomplished by condensation or permeation subsystems.

Sample conditioning system. The third component, the sample conditioning system, provides a clean, dry, interference-free sample to the analyzers. Two moisture removal methods are most frequently used in sample conditioning systems: condensation and permeation.

Condensers remove moisture by rapidly cooling the gas sample before it is analyzed.

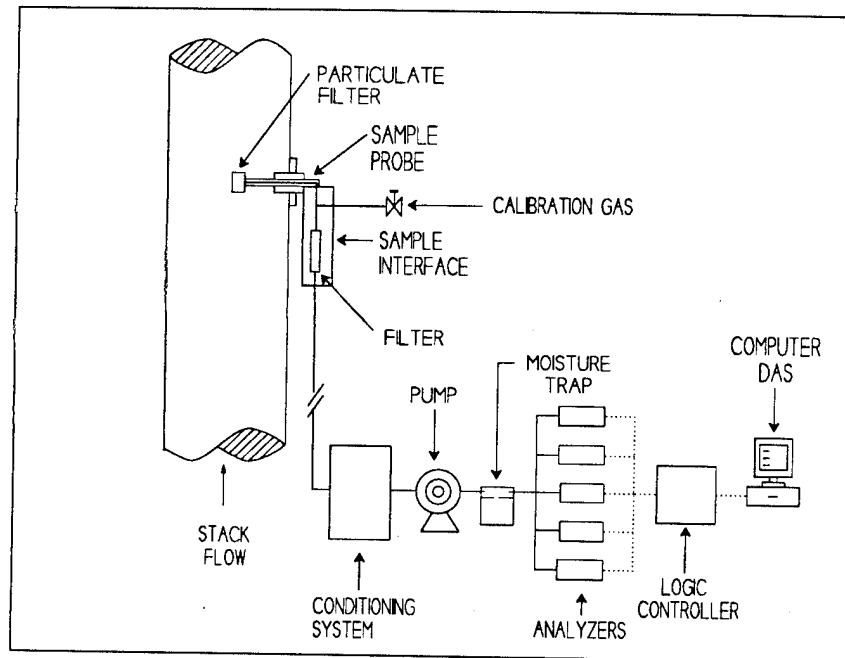
Condensation systems. Condensation systems rapidly cool the sample, thereby condensing sample moisture. The condensed moisture is trapped and periodically removed from the condenser assembly. To avoid absorption of the target gases by the condensed liquid, precautions are usually taken in designing condensers and traps that minimize contact between the condensate and the cooled sample.

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Figure 5-3

Typical extractive emission monitoring system.



Three basic techniques are generally employed to prevent the trapped condensate from contacting the target gases. The first and most common approach uses a standard compressor-type refrigeration unit. More recent approaches are (1) the thermoelectric plate cooler, a solid-state unit with no moving parts; and (2) the vortex chiller that relies on the chilling effect caused by rapid expansion of a compressed gas (usually air).

All three types of condensers have limitations:

- Refrigeration condensers generally require a complex valve and plumbing system (which often requires a high level of maintenance) for adequate moisture removal.
- Thermoelectric coolers are often plagued by leaks around the flat plate seal.
- Vortex coolers require a relatively high compressed air flow rate, and their efficiency is affected by ambient changes in temperature.

Permeation dryers rely on a countercurrent of dry purge air to remove moisture from stack gases.

Permeation dryers. Permeation dryers are occasionally used in place of or in conjunction with refrigerated condensers. This technique is based on the selective permeability of water through a membrane. Permeation occurs continuously as moist stack gas flows in one direction through the dryer, while dry purge air flows countercurrently on the other side of the membrane. Limitations of permeation dryers also exist, including:

- A tendency to become plugged by particulate matter. Efficient filtration and high pressure backpurging of the conditioning system can mitigate plugging, but care must be taken to prevent viscous materials (e.g., oil mists) from reaching the dryers.
- Failure due to the presence of liquid water. If water droplets enter the dryer, its ability to remove water vapor decreases dramatically and ultimately can result in complete failure of the conditioning system.

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More reliable performance of extractive systems is largely due to improved O&M procedures.

Pollutant and diluent analyzers. The fourth component of extractive CEM systems is the pollutant and diluent monitors, which actually measure the various parameters in the effluent. These monitors and their principles of operation are discussed in the section entitled *Gaseous Monitoring Analytical Techniques*, beginning on page 5-9.

Recent Technological Advances

Only limited technological improvements have been made to extractive systems, which have been used extensively over the past 10 years. Probe materials and designs have improved; some probe materials and coatings currently available are more resistant to corrosion, while other materials can withstand temperatures exceeding 3000 °F. Other advances include (1) the availability of easily spliced heated sample lines and (2) the use of secondary conditioners to ensure that particulate matter and moisture removal are adequate for those monitors that measure gas concentrations on a dry basis. Only a limited number of extractive monitors measure gas concentrations on a wet basis; however, several vendors supply a (single) monitor that operates on a wet basis and can measure concentrations of up to eight gases, including moisture and ammonia.

Although these improvements have enhanced the performance of extractive systems, various changes in typical operating and maintenance procedures have had an equal or greater impact on accuracy and reliability. During approximately the first three months of operation, many operators discover that "anticipated" operating and maintenance procedures must be altered to optimize CEM system performance. For example, minimizing sample gas flow rate, providing more filtration at the probe tip, and lengthening purge cycle times might result in optimum monitor reliability and accuracy at one location, while maximizing flow rates, minimizing probe tip filtration, and operating the heated sample line at elevated temperatures might produce the best results at another location.

Extractive system data are extremely accurate, but maintenance requirements can be substantial.

Advantages and Limitations

One of the most significant advantages of an extractive system is that, through implementation of a rigorous preventive maintenance program, extremely accurate data can be obtained, especially at low pollutant concentrations (e.g., less than 100 ppm SO₂). Most system components are remotely located, thereby facilitating accessibility, maintenance, and timesharing between two different sampling locations. This timesharing capability helps offset the higher cost of extractive systems and may be considered as an option for a "backup" monitoring strategy.

In general, extractive systems can require significantly more maintenance than dilution-extractive or in-situ systems (especially during the initial months of operation) due to the exposure of auxiliary equipment to the flue gases. For example, particulate matter filters and moisture condenser traps are prone to plugging until proper maintenance schedules can be established. The heat-traced sample lines are relatively expensive, subject to section failures, occasionally subject to plugging, and often difficult to check when suspended between the stack sampling and analyzer locations. If extractive monitors that measure gaseous concentrations on a dry basis are used to comply with 40 CFR Part 75 regulations, flue gas moisture content must be monitored. Finally, system operation involves several valves that can be damaged by corrosion from the sample gas. Valve failure can be difficult to detect, often resulting in extended maintenance efforts. Installing valves constructed of corrosion-resistant materials, such as Teflon or steel alloys, however, greatly reduces this problem.

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In-situ sampling systems measure gas concentrations directly in the stack or duct.

In-Situ Systems**Commercially Available Equipment**

As the name implies, in-situ gas monitoring systems are designed to measure gas concentrations directly in the stack or duct, without extracting samples for external analysis. Two types of in-situ monitoring systems are currently in use. The first is an across-stack (or path in-situ) system that analyzes the effluent passing by a specific "line of sight" of the monitor, typically ranging from a few feet to the full distance across the interior stack or duct diameter. The second is a point in-situ instrument, which analyzes the effluent at one specific point or along a short path in the stack or duct. EPA distinguishes between path and point analyzers by the percentage of the stack or duct diameter (or equivalent diameter for non-circular ducts) represented by the measurement path. Instruments that measure gas concentrations along a path less than or equal to 10% of the diameter are point analyzers. If the measurement path is greater than 10% of the equivalent diameter, the instrument is considered a path analyzer.

Recent Technological Advances

With the exception of some improvements to the electronic components used in these systems, very few significant changes have been made in the past 5 years. Furthermore, some of the in-situ systems currently available may have difficulty complying with the 40 CFR Part 75 quality assurance/quality control (QA/QC) requirements and calibration procedures.

Adverse ambient conditions require enclosing in-situ systems.

Advantages and Disadvantages

Because in-situ systems are installed in the stack or duct, many difficulties can arise. The system, as well as maintenance personnel, are exposed to ambient dust, severe weather conditions, and effluent that is often wet and corrosive. To protect the system, these units should be installed in enclosures that are large enough to provide personnel with adequate space for system maintenance and testing. It should be noted that, while some utilities have encountered operational difficulties, other utilities with an appropriate level of routine maintenance have successfully operated in-situ systems for years, continually satisfying 40 CFR Part 60 Appendix F requirements. Furthermore, some of the newer in-situ systems have improved calibration capabilities and may prove to be the preferred type of system for satisfying future monitoring requirements (e.g., ammonia or mercury monitoring).

In-situ monitoring systems are subject to interferences caused by particulate matter and entrained water droplets. Techniques used to avoid these interferences include electronic compensation and effluent filtration by passing the sample gas through a measurement cavity to remove particulate matter and moisture. Systems that use an in-stack filter require a high-pressure blowback system to clean the filter. Some systems use heated blowback air to ensure that no condensation develops during this process.

Most optical systems are equipped with a heated air purge system to prevent condensation and particulate matter buildup on the optics. However, the air purge system and associated filters also require routine maintenance to ensure proper operation. Many systems are equipped with a safety feature that causes protective shutters to close over the optics when the air purge system fails.

At temperatures above 500 °F, changes in the effluent gas spectra occur and interferences between the various gases can increase substantially, precluding the use of in-situ systems. Furthermore, extreme care must be taken to ensure that the temperature compensation circuits are functioning properly between 200 and 500 °F.

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Some in-situ systems may not be sufficiently reliable to meet Part 75 data availability requirements.

In addition to these concerns, the utility industry has a general concern that some in-situ monitors may not achieve sufficiently high data capture to avoid the most stringent missing data substitution provisions of the 40 CFR Part 75 regulations. Some in-situ CEM system operators are currently spending 5 to 14 days on one annual refurbishment of their system, in addition to the routine and non-routine maintenance each year. Scheduling annual refurbishing periods with unit outages can be difficult. Consequently, ensuring that the monitor availability for these systems will be high enough to avoid the more punitive Part 75 missing data substitution procedures may be difficult without using backup monitoring systems.

GASEOUS MONITORING ANALYTICAL TECHNIQUES

There are many different types of gaseous (i.e., pollutant concentration and diluent) monitors employing a variety of analytical techniques. The following paragraphs present a general description of the most common types of monitors currently in use and brief discussions of their primary limitations.

Absorbance of particular light wavelengths by flue gases is the principle underlying spectrophotometric analysis.

Spectrophotometric Analysis

CEM systems that use spectrophotometric analyzers (spectrophotometers) rely on the interaction of light energy with gas molecules to determine the concentrations of gaseous parameters. Because light energy and wavelength are directly related, the types of light employed by the analyzer can be referred to by wavelength or spectral region (infrared, visible, ultraviolet). For a specific type of gaseous molecules, only light of certain wavelengths is absorbed by gaseous molecules, while light of other wavelengths is not. This physical property allows the design of numerous detection devices that can operate in different ranges of the spectrum, while allowing a degree of selectivity to be built into the analyzer.

Spectrophotometers may be either non-dispersive or dispersive. A non-dispersive analyzer does not separate, or disperse, the transmitted light into its component wavelengths. Rather, the analyzer uses a broad band of wavelengths centered at the absorption peak of a target gas. These analyzers can operate in all three spectral ranges and are capable of determining the concentration of several pollutant gases. Conversely, dispersive spectrophotometers separate the light energy into its component wavelengths. This separation allows the selection of the specific light wavelength that optimizes the analysis of the gas of interest. However, such selective techniques generally limit the instrument to the analysis of one particular gas.

NDIR analyzers use IR light heat reference and sample gas cells creating a pressure differential proportional to the target gas concentration.

Non-Dispersive Absorption Spectrometers

Non-dispersive infrared (NDIR) monitors. NDIR monitors can analyze SO₂, NO_x, CO₂, CO, and other gases. These analyzers typically employ a dual-beam (reference and sample) optical system with one of several types of detectors. Infrared radiation of equal intensity is passed through both the sample and reference cells. The reference cell is filled with a dry gas that does not absorb the infrared radiation. Sample gas flows continuously through the sample cell. The light passing through the sample cell is partially absorbed by the sample gas.

After the light has passed through the reference and sample cells, it enters the detector section of the analyzer where the difference in intensity of the light passing through the reference and sample cells is measured. Typically, microphone detectors (also known as Luft detectors) are used in NDIR analyzers. These detectors are gas-filled cells with two compartments separated by a flexible metal diaphragm. The gas filling the two chambers is the same as the gas being analyzed. The analyzer can distinguish between different gas species, because only infrared radiation in a specific band is absorbed by the detector. As the light passing through the reference and sample cells enters the detector, the gas molecules inside the detector are heated. Due to the

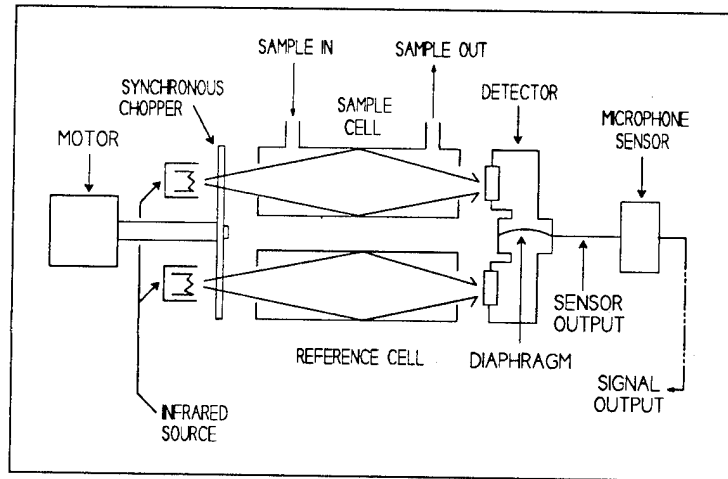
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absorption of infrared energy in the sample cell, the intensity of the two light beams differs, and a pressure differential develops between the two chambers as they become heated to different temperatures. This pressure difference causes a movement in the diaphragm separating the two chambers that is sensed as a change in detector cell capacitance. The greater the displacement, the greater the amount of target gas in the sample. Change in the detector capacitance modulates a radio frequency signal that is rectified and amplified to provide a signal output of gas concentration, which is then displayed by a readout device. To make the signal easier to detect and amplify, the infrared light beams are intermittently interrupted by a rotating chopper wheel, creating an alternating signal in the detector. A typical NDIR analyzer configuration with a microphone detector is illustrated in Figure 5-4.

Figure 5-4

Typical non-dispersive infrared analyzer.



Other detectors commonly used include microflow and solid state detectors. In a microflow-based detector, a differential pressure is developed by absorption of light energy by gas in one of two gas chambers. These chambers are connected by a small path, and a flow of gas is created by the differential pressure. This flow is converted to ac electrical signals by a microflow sensor. The ac signals are amplified and rectified into dc signals, which are proportional to the target gas concentration in the sample. Except for the detector, the physical arrangement of the components of this type of instrument is essentially the same as that shown in Figure 5-4 for the typical microphone detector-based instrument.

The arrangement of components in a solid state detector-based NDIR instrument is also similar to that illustrated in Figure 5-4. In this case, the detector is based on using a semiconductor photodetector. The intensity of the light passing through the sample and reference cells is alternately measured by a solid state photodetector, with the difference being proportional to the target gas concentration in the sample.

NDIR analyzers can measure a variety of gases, but nontarget gases may interfere.

The primary advantages of NDIR analyzers are the broad range of gaseous species they are able to detect and their relatively low price. One of the most important limitations of NDIR analyzers is the presence in the sample gas of interfering gases that absorb infrared light at the same frequencies as the target gases. The infrared band centers of some common gases are shown in Table 5-1.

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One of two techniques is typically used to reduce interferences: the interfering gas is removed from the sample before analysis, or a filter cell is added in the optical path to remove light of wavelengths common to both the target and interfering gases. (See *Gas filter correlation (GFC) monitors*, page 5-12.)

Table 5-1

Infrared Band Centers of Some Common Gases

Gas	Location of Band Centers (μm)	Wave Number (cm^{-1})
NO	5.0 - 5.5	1800 - 2000
NO ₂	5.5 - 20	500 - 1800
SO ₂	8 - 14	700 - 1250
H ₂ O	3.1	1000 - 1400
	5.0 - 5.5	1800 - 2000
	7.1 - 10	3200
CO	2.3	2200
	4.6	4300
CO ₂	2.7	850 - 1250
	5.2	1900
	8 - 12	3700
NH ₃	10.5	950

Source: LBL-1, "Instrumentation for Environmental Monitoring," Lawrence Berkeley Laboratory, University of California. September 1976. Part 1, II.D., p. 40

Other limitations of NDIR analyzers follow:

- Sensitivity to vibration. Vibration causes high background signal noise that can ultimately damage the detector cell. This problem is not as significant in instruments with microflow or solid state detectors.
- Sensitivity of the optics to corrosion.

NDUV analyzers use UV light to detect optical differentials in sample and reference gas cells.

Non-dispersive ultraviolet (NDUV) monitors. NDUV monitors use a technique similar to NDIR instruments to quantify SO₂ and NO_x but, as the name implies, operate in the ultraviolet and high frequency visible regions of the light spectrum. NDUV and pulsed NDUV (for SO₂) analyzers use a reference wave-length of light that is not absorbed in the effluent gas sample in conjunction with a sample wavelength of light that is absorbed by the target gas. Because ultraviolet light does not heat gas molecules as infrared light does, a different detection method is used (e.g., silicon photodiode detectors). Typically, a beam of ultraviolet light passes through the sample cell to a beam splitter. The splitter directs a portion of the light to a reference detector and the remaining light to a sample detector. Optical filters or mirrors with selective wavelength reflections are positioned between the beam splitter and photomultiplier detectors, allowing only a narrow band of light (specific to the reference wavelength being used and the gas under analysis) to continue to the detectors. The resulting photomultiplier signals are processed, amplified, and output as a value proportional to the concentration of the target gas. Some newer SO₂ analyzers have reference and sample detectors before and after the sample cell in order to minimize potential interference.

When using NDUV analyzers to determine NO_x concentrations, nitrogen oxide (NO) (which for all practical purposes does not absorb ultraviolet light) must be converted to nitrogen dioxide. To accomplish this conversion, the cell receives a fresh sample of effluent gas, and when the cell is com-

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pletely purged, the flow into the cell is stopped; the cell is then pressurized with oxygen. Once the additional oxygen has converted the NO to NO₂, the concentration of NO can be determined from the differences in readings before and after the oxidation step.

In terms of relative advantages, NDUV analyzers are more sensitive than their NDIR counterparts, and they are subject to fewer interferences. Because water vapor is not an interference, it does not necessarily have to be removed. However, the gas sample must be heated above its dew point, and particulate matter must be filtered from the sample gas.

GFC analyzers measure the difference between (correlation) IR light absorbance by a standard target-gas filter and the sample gas.

Gas-filter correlation (GFC) monitors. Gas-filter correlation spectroscopy is based on measuring the difference between the absorption of light by a reference gas filter consisting of pure (100%) target gas and the absorption of light by the sample gas. Commercially available GFC analyzers operate in the infrared region. This design allows one analyzer to determine the concentrations of several components of the effluent. GFC spectroscopy is used with both in-situ and extractive CEM systems.

In GFC systems, light emitted from a lamp passes through the sample to an analyzer where it is split into two separate beams. One beam passes through a neutral filter and the other through a gas-filter correlation cell. This cell contains 100% target gas so that all of the energy contained in the individual absorption lines of the gas will be removed. Light of wavelengths not absorbed by the specified gas is not removed and passes on to the detector. This results in a reduction in light energy after the beam traverses the correlation cell.

Molecules having similar spectral absorption patterns to the flue gases will interfere with GFC analysis.

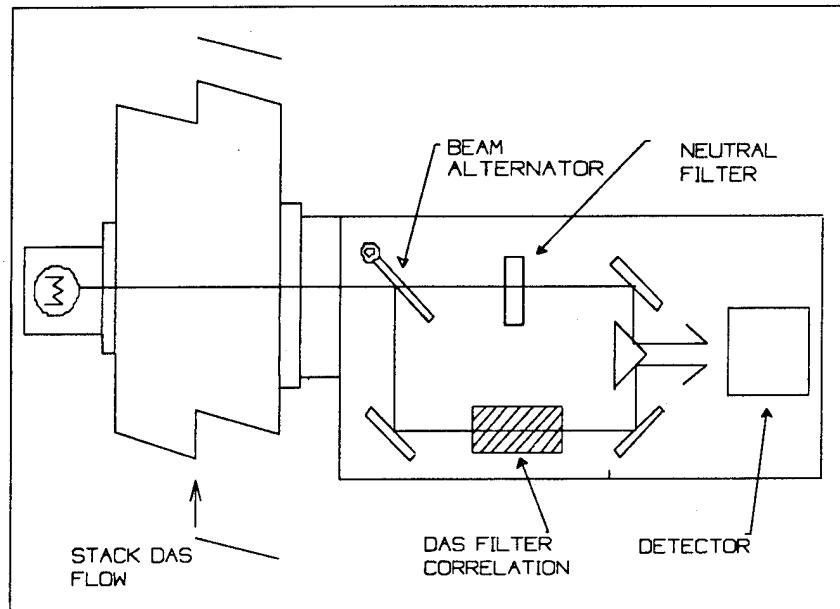
In most GFC instruments, a neutral density filter is used to reduce the amount of light energy in the sample beam by an amount equal to the correlation filter cell in a clear path (or stack) condition. The neutral density filter reduces the energy from all of the wavelengths in the beam before it reaches the detector. Because the gas-filter correlation cell absorbs energy at the wavelength of the target gas, the absorption is already complete in the correlation cell beam, and the detector will measure the same signal as if the stack were clear. However, while sampling, the beam passing through the neutral density filter will have even less energy than it had previously, since some light had been selectively absorbed by the target gas in the stack. The difference in energy between the two beams can be related to the concentration of the target gas and is monitored at the detector (see Figure 5-5). Particulate matter will reduce the intensity equally in each of the beams, and because the two signals are ratioed, the effect of particulate matter will cancel. Molecules with spectral patterns near that of the pollutant molecule being measured will not affect the measurement if they do not "correlate" or overlap with the pollutant spectral pattern. To the extent that overlap occurs, interference will result.

Dispersive Absorption Spectrometers

Dispersive absorption spectroscopy has seen limited use in conventional CEM technology. Dispersive absorption spectrometers are instruments that can be set at a wavelength within a specific range. This differs from a non-dispersive type of instrumentation, which looks at a broad spectral region and must be sensitized for each particular gas by means of a detector cell. Dispersive instruments can measure any gas within its spectral region and are not limited to a single, preselected gas. The sensitivity of dispersive absorption spectrometers is relatively high, and instruments based on this technique can measure several gases simultaneously. However, absorption in the spectral region of other gases, water vapor, or particulates may create some problems.

Figure 5-5

Typical cross-stack gas filter correlation spectrometer.



Second-derivative spectroscopic analyzers use specific light wavelengths corresponding to maximum absorption peaks of target gases.

The technique of second derivative spectroscopy uses a method of dispersive spectroscopy, which is unique in CEM systems. A diffraction grating allows only specific wavelengths of light to be emitted from the light source. This diffraction grating scans back and forth across a central wavelength that corresponds to the maximum absorption peak of the target molecule. The results of this scan, as seen at the instrument detector, are a gradual decrease in light transmission to a minimum value, followed by a gradual increase. Therefore, the resulting detector signal varies at a frequency of twice the scan rate of the diffraction screen. The amplitude of the signal is directly related to the concentration of the target gas (see Figure 5-6).

Electronically, the concentration of the target gas is determined by selecting a frequency that is double that of the movement frequency of the scanner. In second derivative analyzers, the instrument is tuned to a frequency of $2f$, where f is the scanning frequency of the grating. A strong signal from the detector indicates strong absorption and a high concentration of the target gas. A weak signal at this frequency indicates a lower concentration of the target gas.

Second derivative spectroscopy is extremely sensitive, but vibration can interfere with optics.

Second derivative spectroscopy is not subject to any significant interferences and is an extremely sensitive analytical method. It does, however, have the following primary limitations:

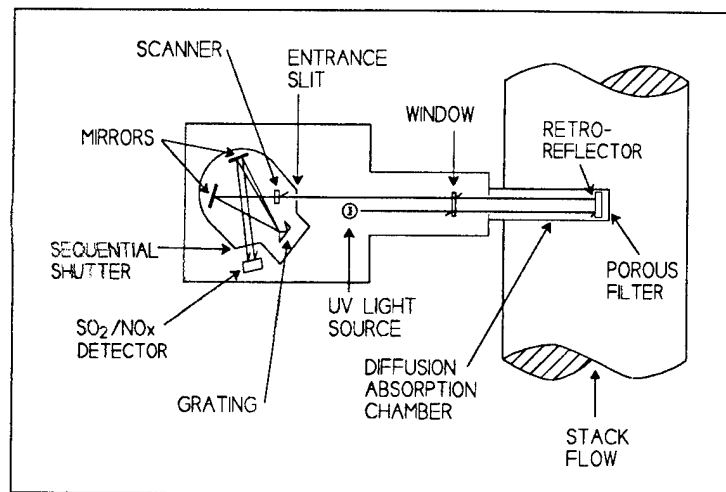
- Severe vibration can interfere with the required movement of the optics.
- Interchannel sensitivity and interaction. In models that monitor both SO_2 and NO_x , the use of common components within the analyzer can result in decreased accuracy for one of the two channels.

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Figure 5-6

Typical second derivative in-situ monitor.



Luminescence analyzers use light or chemical reactions to excite gas molecules that emit light when returning to a lower energy state.

Luminescence Analysis

Two types of luminescence analyzers are used in CEM systems: photoluminescence analyzers and chemiluminescence analyzers. Photoluminescence (or fluorescence) analyzers irradiate the sample gas with light at a specific wavelength that is absorbed by the target gas. The target gas molecule, now at a higher energy state, will immediately try to lose this additional energy. One way to lose this energy is to fluoresce, or emit light energy. The wavelength of this light differs from the wavelength of the excitation light and can be detected by a photomultiplier type detector.

The primary limitation of fluorescence analysis is quenching. Quenching occurs when the excited molecule loses its energy by colliding with another gas molecule. In the presence of oxygen, quenching is significant, and care must be exercised to use span gases containing an amount of oxygen closely approximating effluent conditions.

Chemiluminescence is the radiation of light that results from a chemical reaction and is used for NO_x determinations. The NO_x method uses ozone to oxidize NO into an excited molecule of NO_2 . The NO_2 molecule then emits a luminescent light, which is sensed by a photomultiplier detector. NO_2 does not undergo this reaction and must first be converted into NO using a high-temperature converter or by catalytic reduction. The primary limitations of chemiluminescence analysis follow:

- Capillary tubing used to meter precise volumes of sample gas and ozone can become plugged.
- Converter efficiency of the NO_2 to NO reduction catalyst will decrease over time, resulting in erroneously low NO_x concentration measurements. The high-temperature converters are less susceptible to efficiency problems, but operate at temperatures high enough to convert ammonia to NO, as well.
- Quenching can occur.

Chemiluminescence analyzers are subject to quenching in the same manner as fluorescence analyzers. When using high-temperature converters, ammonia is the major interference, although it is not typically a major constituent of power plant effluents. If ammonia is present in significant concentrations, it can be removed from the sample gas by selective scrubbing or a low-temperature catalytic converter may be used.

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Polarographic and electrocatalytic analyzers rely on electrochemical reactions of the target gas molecules with electrolytic solutions or compounds.

Electrochemical Analysis

Several types of CEM analyzers are based on various polarographic and electrocatalytic methods. Polarographic analyzers capable of measuring a number of pollutant gases are available and can be relatively inexpensive. In addition to portable monitoring instrumentation, several CEM manufacturers offer permanent CEM systems that utilize polarographic analyzer. Electrocatalytic monitors are available for dilution, extractive, and in-situ systems.

Polarographic Monitors

Polarographic analyzers are also known as voltametric analyzers or electrochemical transducers. By proper selection of electrodes and electrolytes, instruments based on polarography have been developed for monitoring SO_2 , NO_2 , CO , O_2 , and other gases. The transducer in these instruments is generally a self-contained electrochemical cell in which a chemical reaction involving the pollutant molecule takes place. Two basic techniques are used in these transducers: (1) a selective semipermeable membrane allows the target molecule to diffuse to an electrolytic solution, and (2) the current change produced at an electrode by the oxidation or reduction of the dissolved gas at the electrode is measured. The electrons generated at the sensing electrode create an electric current that is proportional to the concentration of the target gas.

Stack gases must be brought to ambient temperatures, and particulates and water vapor must be removed, for polarographic monitoring.

In their earlier development, polarographic analyzers were temperature sensitive, but temperature compensation devices are now typically used to mitigate this problem. Conditioning the sample gas before it enters these analyzers is critical. The stack gas should be brought to ambient temperature, and particulate matter and water vapor must be removed to avoid contaminating the cell membrane. The electrolyte of the cells is usually consumed in three to six months of continuous use, requiring the user to either return them to the supplier for recharging or purchase new cells.

Electrocatalytic Monitors

As an outgrowth of fuel-cell technology, a new method for determining O_2 concentrations has developed over the past several years. "Fuel-cell" oxygen analyzers are not actually fuel cells, but simple electrolytic concentration cells that use a special solid catalytic electrolyte to aid in electron flow. These analyzers are available in dilution, extractive, and in-situ configurations. An example of an in-situ electrocatalytic monitor is shown in Figure 5-7. The versatility of their design has made these analyzers popular for monitoring O_2 concentrations in exhaust gas effluents.

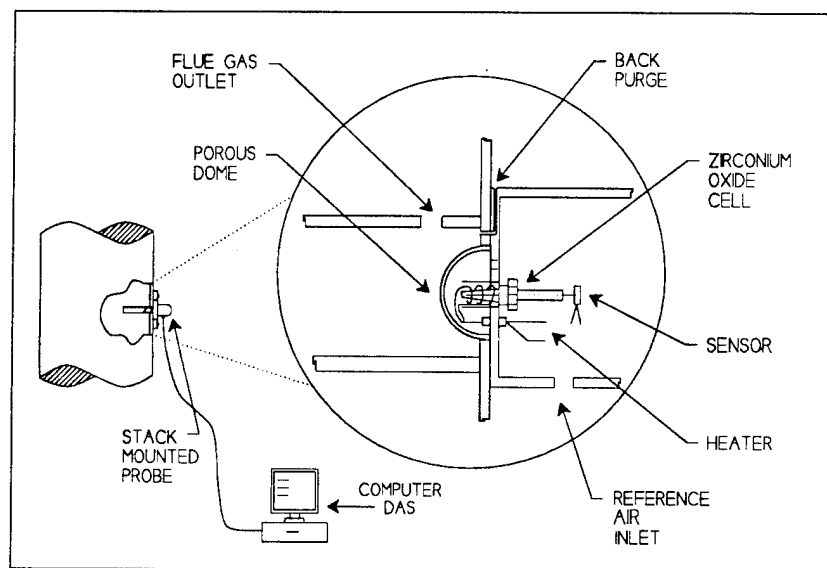
Electrocatalytic analyzers measure oxygen in terms of partial pressure. A special porous material, zirconium oxide (ZrO_2), serves both as an electrolyte and a high temperature catalyst to produce ionized oxygen. The porous ceramic ZrO_2 has the special property of high conductivity of oxygen ions. When sampling combustion gases, the oxygen partial pressure in the sample side will be lower than that in the reference side (which is typically that of the ambient air). Maintaining such a cell at a temperature of approximately 800°C causes oxygen molecules on the reference side to pick up electrons at the electrode-electrolyte interface.

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Figure 5-7

In-situ electrocatalytic system with a zirconium oxide cell.



Electrocatalytic O_2 analysis can be affected by hydrocarbons and CO .

The primary limitation to electrolytic cells is the presence of combustible compounds (e.g., carbon monoxide and hydrocarbons), which may burn and lower the effective oxygen concentration. This limitation is usually insignificant in utility applications, however, because exhaust gases typically contain low concentrations of such combustible materials.

Paramagnetic analysis is based on the characteristic attraction of O_2 molecules in magnetic fields.

Paramagnetic Monitors

When molecules are placed in a magnetic field, they behave either diamagnetically or paramagnetically. Most molecules are diamagnetic and will be repelled when placed in a magnetic field. Some molecules are paramagnetic and are attracted by a magnetic field. Oxygen molecules display paramagnetism, a property that is the basis for three types of commercial O_2 analyzers: thermomagnetic, magnetodynamic, and magnetopneumatic. If the concentration of NO and NO_2 (which are also paramagnetic) is high relative to O_2 concentration in the flue gas, some small interference may occur. The commercial use of paramagnetic analyzers is limited to the measurement of oxygen concentrations. Monitors based upon the paramagnetic principle require a clean, dry gas, and thus are limited to use in extractive systems.

Thermomagnetic Monitors

Thermomagnetic instruments are based on the principle that paramagnetic attraction of oxygen molecules decreases as the temperature increases. A typical magnetic wind analyzer uses a cross-tube wound with filament wire and heated to $200^\circ C$. A strong magnetic field is applied to one half of the coil. Oxygen in the sample gas will be attracted to the applied field and enter the cross-tube, where it becomes heated and its paramagnetic susceptibility reduced. The heated oxygen will then be pushed out by colder gas entering the cross-tube. As a result, a "wind" or flow of gas will continuously pass through the cross-tube and effectively cool the heated filament coil, changing its resistance. The change in resistance, detected in a Wheatstone bridge circuit, can then be related to the oxygen concentration. The principal limitations of thermomagnetic analyzers are

- The cross-tube filament temperature can be affected by changes in the thermal conductivity of the carrier gas (the gas composition must be relatively stable to obtain consistent results).

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- Unburned hydrocarbons or other combustible materials may react on the heated filaments and change their resistance.

Magnetodynamic Monitors

Magnetodynamic analytical techniques utilize the paramagnetic property of oxygen molecules by suspending a specially constructed torsion balance in a magnetic field. In these analyzers, a dumbbell-shaped platinum ribbon is used, and because platinum is diamagnetic, the dumbbell is repelled slightly from the magnetic field. When a sample containing oxygen is added, the magnet attracts the oxygen and field lines surrounding the dumbbell are changed. The dumbbell will then try to swing to realign itself with the new field. Light reflected from a small mirror on the dumbbell as it begins to swing is detected by an optical system consisting of twin photocells connected to an amplifier. A current is passed from the amplifier through a coil wrapped around the dumbbell. The current required to return the ribbon to its original position (counteracting the change in the magnetic field that resulted from the presence of O_2) is proportional to the O_2 concentration.

Magnetopneumatic Monitors

Magnetopneumatic monitors (shown in Figure 5-8) are a relatively new type of paramagnetic monitor, which rely on a technique that compares the magnetic properties of a reference gas with those of the sample gas. When the boundary surface between the reference gas and the sample gas is placed in a magnetic field, the force acting on this surface is proportional to the concentration of O_2 in the sample gas: O_2 enhances the magnetic field in the sample cell. The change in pressure causes movement of a membrane, which is detected by either photocells or a condenser microphone.

Paramagnetic monitors are highly selective for O_2 and relatively interference free.

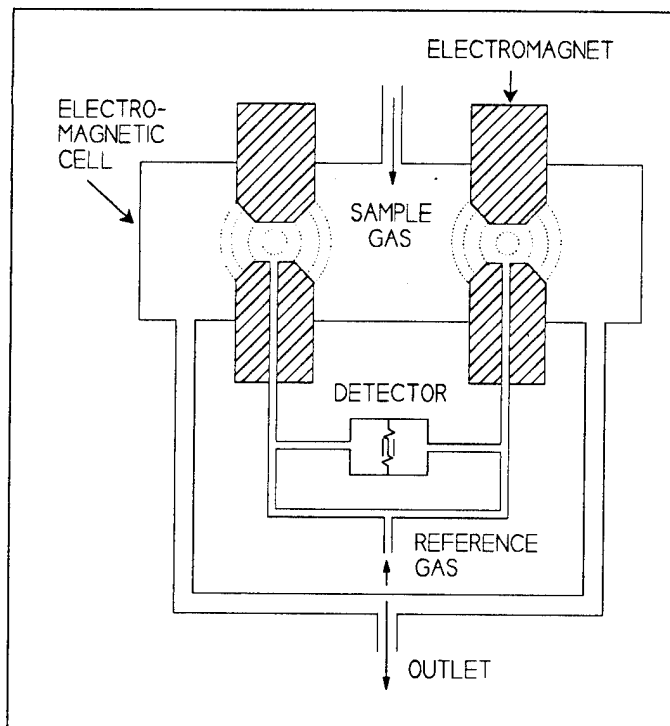
In general, the principal advantage of any paramagnetic monitor is selectivity – that is, only one parameter, O_2 , is detected with very little interference from other compounds. Thermomagnetic monitors tend to be less accurate than other paramagnetic monitors, due to some sample gas reaction with the heated filaments. A wide fluctuation of the thermal conductivity of the sample gas, as well as a buildup of unburned materials on the filament, can adversely affect the monitor readings. The cross-tube filament must also remain absolutely horizontal to avoid errors resulting from gravitational flow effects. Magnetodynamic and magnetopneumatic monitors can also be sensitive to vibration, as well as wide fluctuations in flow rate.

Certain advances have enhanced the operation of paramagnetic monitors in general. Monitor longevity has been increased by isolating the solid-state electronics from the sample gas. Improvements of other system components have decreased the influence of diamagnetic gases (e.g., nitrogen) on the analyzer response. The monitors also offer improved accessibility and ease of maintenance. As with other types of analyzers, depending on the instrument, standard or optional functions include compensation for barometric pressure, automated calibration, and alarms.

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Figure 5-8
Magnetopneumatic analyzer.



COMMERCIALLY AVAILABLE GASEOUS MONITORS

The following subsections provide a brief overview of the commercially available SO_2 , NO_x , CO_2 , and O_2 monitors and their principles of operation. A list of monitors available from CEM system manufacturers and the analytical principles they use is provided in Appendix J of this Guidelines Manual.

Available SO_2 analyzers include those based on UV spectrometry, fluorescence, and flame photometry.

SO_2 Monitors

SO_2 monitoring technologies are well established and only incremental advances have been made in recent years. A brief overview of these technologies follows, along with brief discussions of the advantages and shortcomings of each.

UV Spectrophotometric Monitors

Several vendors offer UV and second-derivative spectroscopic UV SO_2 monitors for in-situ and extractive applications. UV type SO_2 monitors have proven to be reliable instruments, and as with many other monitoring systems, electronic components (e.g., for optical contamination and lamp current compensation) have been improved over the past 5 years.

Fluorescence Monitors

Pulsed-fluorescence SO_2 analyzers were originally manufactured for ambient air monitoring. These units operate well at low concentrations, and so fluorescence technology is being used widely in dilution-extractive systems. Presently, nine companies manufacture or use pulsed-fluorescence analyzers for SO_2 monitoring.

Problems associated with quenching and other interferences have been somewhat reduced through advances in optical filtering. However, using calibration gases containing approximately the same O_2 and CO_2 concentra-

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tions as the flue gas is recommended when fluorescence monitors are used in extractive CEM systems to minimize quenching. This precaution is not necessary when fluorescence monitors are used in dilution-extractive CEM systems with a dilution ratio greater than approximately 20:1, because the quenching effect of O₂ in the dilution air dominates and is taken into account during calibration.

Note that several vendors are now marketing microprocessor-based electronics for these monitors that will enhance performance and overall reliability.

Flame Photometric Monitors

Currently, at least one CEM system vendor offers a flame photometric SO₂ monitor for use in a dilution-extractive system. Flame photometric analyzers detect the light emitted at a wavelength of 394 nm from combustion of sulfur compounds in a hydrogen-rich flame. The light is filtered and detected by a photomultiplier tube. When analyzing for SO₂ only, the sample gas must be filtered to remove particulate sulfates and may be scrubbed to remove hydrogen sulfide.

Flame photometric monitors are generally more accurate than UV monitors at low concentrations and do not rely on a light source with a short life span. The primary disadvantage to using flame photometry is that hydrogen gas is required for the flame source. The special safety and liability concerns associated with handling hydrogen gas cylinders are a hindrance.

NO_x Monitors

Chemiluminescence and UV spectrometry are the principal technologies used today in NO_x monitoring.

Typically, chemiluminescence or UV monitors are used for monitoring NO_x. Recent advances, particularly for chemiluminescence monitors, are noted in the following brief overviews of these long-established monitoring technologies.

Chemiluminescence Monitors

Presently, more than ten chemiluminescence monitors are available for NO_x monitoring. These monitors have been installed and operated at utility sites for years and have a proven performance record.

As with SO₂ monitors, several of these monitors now incorporate a microprocessor, enabling the operator to check certain monitor operating parameters, perform calibrations automatically, and perform numerous diagnostic functions. If ammonia interference is a potential problem, catalytic converters are available that will convert NO₂ to NO without converting ammonia to NO. Essentially all chemiluminescence monitors incorporate a high-vacuum sample chamber to minimize quenching (absorption of the fluorescent light by other molecules).

Chemiluminescence monitors do have some drawbacks, however. The catalytic converters must be replaced periodically (usually about once every six months for extractive systems and two to five years for dilution-extractive systems) to ensure complete conversion of NO₂ to NO, and the capillary tubing used to regulate sample by-pass and ozone flow rates can become plugged without proper gas conditioning. When using reference method NO_x monitors for backup, note that NO₂ to NO converters are not required for NO_x monitoring according to Method 7E (Appendix A, 40 CFR Part 60) when the NO₂ portion of the flue gas is less than 5% of the total NO_x concentration (as is the case for most utility monitoring applications). Part 75, however, does not address this point.

UV Spectrophotometric Monitors

Several vendors offer UV photometric and second-derivative spectroscopic analyzers for monitoring NO_x. As with the chemiluminescence monitors, UV

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monitors have been used to monitor NO_x emissions at numerous utility sites. UV photometric analyzers require sample filtering to remove particulate matter and sample conditioning or heated sample cells to maintain the sample gas temperature above the dew point. Various design modifications and improvements to the electronic components (e.g., isolating the electronic and optic components from the sample cell) have been implemented. These monitors contain few or no moving parts, and maintenance is relatively easy compared with chemiluminescence monitors.

Virtually all CO₂ analyzers rely on IR-based detection principles.

CO₂ Monitors

Essentially all CO₂ monitors use IR-based technologies to detect CO₂. At least ten NDIR monitors and several GFC monitors are currently available to measure CO₂ concentrations. Other IR CO₂ monitoring technologies may be available in the near future. (See subsequent discussion of Fourier transform infrared analyzers, page 5-28.)

As with other types of IR monitors, these monitors are subject to moisture and particulate matter interference. Except for some microprocessing capabilities and electronic components, no significant improvements have been made in recent years.

In general, CO₂ monitors are considered to be less reliable and less accurate (for the concentration ranges typically observed in flue gas) than O₂ monitors. When using a dilution-extractive CEM system, however, the relative differences, advantages, and limitations between CO₂ and O₂ monitors are not an issue. A CO₂ monitor must be used to determine diluent concentrations for a dilution-extractive CEM system.

All O₂ monitors available for current commercial application are based on paramagnetic properties of O₂ molecules.

O₂ Monitors

Currently, several magnetodynamic monitors and magnetopneumatic monitors, and at least two other types of paramagnetic monitors are being marketed. Thermomagnetic O₂ monitors may no longer be commercially available in that no information on this type of monitor was identified in vendor-supplied literature reviewed during preparation of this manual. Additional information on O₂ monitors is provided on page 15 of this section.

FLOW MONITORING TECHNIQUES

Most commercially available flow monitors operate using one of three principles for measuring velocity and volumetric flow: ultrasonic pulse detection, differential pressure, and thermal detection (convective cooling). The three varieties of flow monitors are stack or duct mounted and operate as a component (including a microcomputer, pressure transmitters, and temperature transmitters) of a system. Other types of flow monitoring systems are available: acoustic, fan efficiency, and infrared detection, but sufficient data are not available to evaluate their performances fairly.

Proper flow monitor installation is critical for ensuring accurate data as well as regulatory compliance. Section 6 of this Guidelines Manual provides an in depth discussion of regulatory installation requirements.

Ultrasonic Flow Monitors**Principle of Operation**

The volumetric flow rate of stack gas is measured by transmitting ultrasonic pulses across the stack in both directions (see Figure 5-9). The tone pulses are accelerated or retarded due to the gas velocity in the stack. The time required to traverse the distance of the stack traveling with and against the flow is a function of the sound velocity and the effluent velocity. Stack flow can be calculated based on the difference in the times required to traverse the stack in both directions. The ultrasonic pulses must traverse the stack or

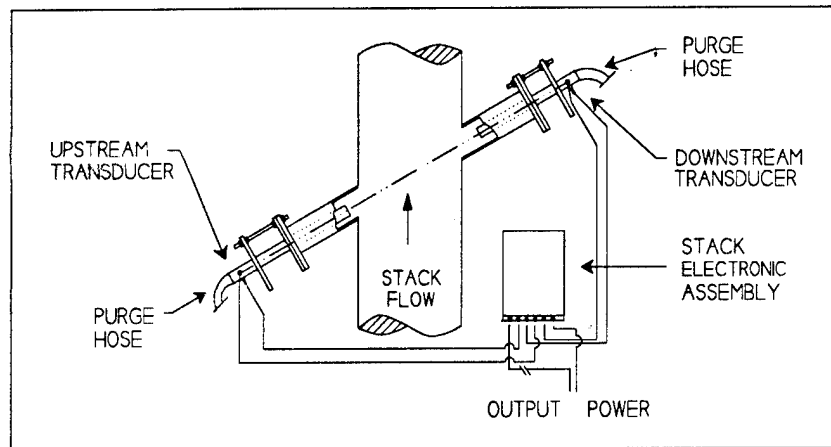
Ultrasonic flow monitors determine stack gas flow rates by measuring the time required by sound pulses to traverse the stack with and against gas flow.

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duct at a minimum angle of 10 degrees; however, traverses between angles of 40 and 70 degrees tend to provide the best results, as long as the traverse path length is not so long that the ultrasonic pulses become difficult to detect.

Figure 5-9
Typical ultrasonic flow system.



Ultrasonic flow monitors are relatively free from corrosion, but maintenance is complicated by the need to install transducers at two elevations.

Advantages and Limitations

Ultrasonic flow monitors offer several advantages. Measurement components of ultrasonic flow monitors are not exposed to flue gas, because the transducers do not extend into the stack or duct and they are isolated from the flue gas by purge air. Thus, corrosion problems are significantly less than with differential pressure and thermal flow sensors. Other advantages are that the monitor reading is an average across the stack, and the technique is non-intrusive.

A disadvantage, however, is that components installed on a stack or duct are placed at an angle, and consequently, the two transducers are mounted at different elevations, which may complicate installation and maintenance efforts, as well as increase capital costs because of the need to provide an additional platform. Precautions must also be taken to either avoid or properly handle condensed moisture in sensor mountings. As with any flow monitor, turbulent or stratified flows may result in erroneous flow rate measurements or require the use of multiple ultrasonic monitors arranged in a crossing pattern.

Differential Pressure Flow Monitors

Three different types of commercially available flow monitoring devices are based on measuring differential pressure: annubars, S-type pitot tubes, and the Fechheimer dual-manifold, pitot probe. The principles of operation, which differ somewhat among these three types of flow monitoring devices, are discussed in the following three paragraphs.

Principle of Operation

Differential pressure flow monitors measure stack gas flow rates by determining the relative difference in impact and wake pressures.

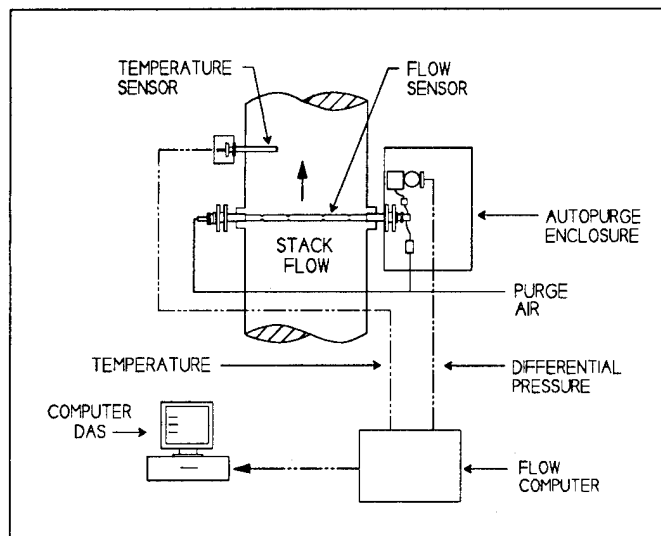
The annubar is a multipoint, dual-chambered probe. The probe averages multiple in-line (impact and wake pressures) sample points across the stack diameter (Figure 5-10). The position and number of points are typically determined using Method 1 in Appendix A to 40 CFR Part 60. The interior of the probe consists of tubes within a tube. The exterior tube shrouds two averaging chamber tubes (Figure 5-11). The inner tubes consist of the impact differential pressure chamber and the wake differential pressure chamber. Precision pressure points are tapped through the exterior tube into the inner

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tubes. The pressure registered at the flow transmitter is the average across the stack.

Figure 5-10
Flow analyzer stack configuration.

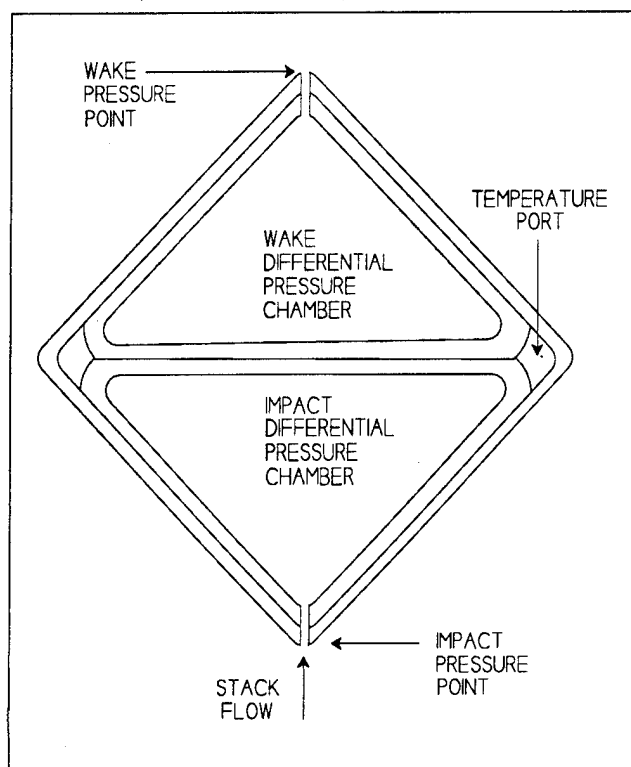


The S-type pitot tube is designed after the Stausscheibe or reverse type pitot tube as stated in Method 2 in Appendix A to 40 CFR Part 60. The probe is constructed of two in-line tubes. The sampling point of the probe consists of two opposing open faces perpendicular to the traverse axis. A side view of the probe resembles two stacked tubes with the ends tapered away from one another and the openings planed parallel to the horizontal axis. Several probes are required for multipoint monitoring. The position and number of points are determined using Method 1 in Appendix A to 40 CFR Part 60. The multipoint averaging is performed in a pitot manifold and the averaged pressures are registered by the flow transmitter.

The Fechheimer pitot probe consists of flow sensors mounted on two multipoint averaging manifolds. The probe design consists of two manifolds (tubes) welded together with a truss plate. The truss maintains a distance between the manifolds in a plane perpendicular to the flow and the stack wall. One manifold averages multiple points of impact pressure, and the other averages multiple points of wake pressure. The impact and wake pressure averages are registered by the flow transmitter.

All of these systems include an electronic, flow-indicating transmitter that receives pressure and temperature signals from the stack, calculates the exhaust gas flow rate, and, as an option, automatically performs electronic drift checks and system purging. Presently, several vendors manufacture flow monitoring equipment for each of the differential pressure techniques.

Figure 5-11
Differential pressure flow analyzer cross section.



Differential pressure probe replacement cost is minimal, but additional air supply equipment may be needed.

Advantages and Limitations

Differential pressure flow monitors can require extremely large amounts of purge air, often necessitating the purchase of additional air supply equipment. Although differential pressure probes can be manufactured from materials that can withstand corrosion and high temperatures, corrosion (especially when high particulate matter concentrations exist at the monitoring location) can still be a serious problem. All pressure differential systems have a back purge system to prevent plugging, which appears to work fairly well. Differential pressure systems typically have sensors that can be easily replaced at minimal cost, which is an advantage relative to ultrasonic systems. Pitot tube systems are adaptable for multipoint analysis, but become very complicated with multiple tubes. A multipoint pitot tube system is adaptable to any stack diameter, but the multitube assembly is only one component of a system, which also includes a microcomputer, pressure transmitters, and temperature transmitters. Annubar probes appear to be less susceptible to turbulent flow problems, relative to the other types of differential pressure flow monitors. Utility industry experience with Fechheimer dual-manifold, pitot probes is limited. It should also be noted that differential pressure systems may work best in extremely wet effluent streams.

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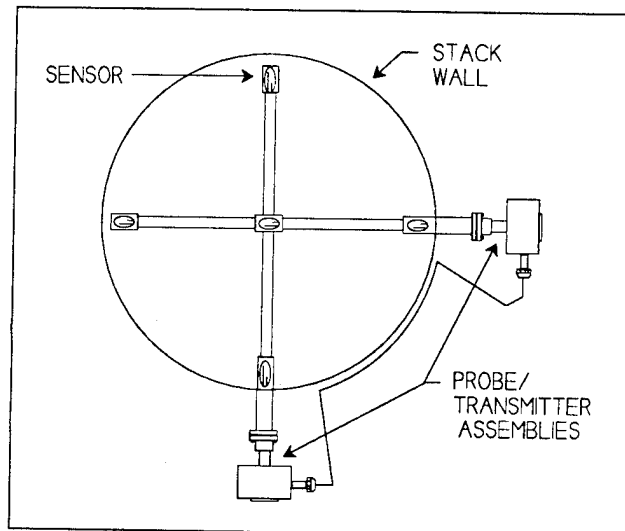
Thermal flow monitors measure the electrical power required to heat a sensor (cooled by convective gas flow), which is proportional to flue gas flow rate.

Thermal Flow Monitors

Principle of Operation

Thermal flow monitors (as shown in Figures 5-12 and 5-13) measure the electric power required to maintain a constant temperature of approximately 75 to 100 °F above the exhaust gas temperature in a flow sensor. The power required to heat the sensor (at any given temperature) is proportional to the convective cooling effect of the exhaust gas. Consequently, by correcting for temperature fluctuations, exhaust gas flow rates can be related to the electric power. Three major manufacturers produce thermal dispersion-type monitoring equipment, which all operate using the same technology. The designs vary, however, in the number of heated elements and thermocouples placed in the stack gas. The monitors are available for both single-point and multi-point analysis, and non-sensing components of the systems can be constructed from various corrosion-resistant metals.

Figure 5-12
Thermal flow stack configuration.



Thermal flow monitors are accurate under varying loads and at very low flow, but cannot be used where water droplets are present in the effluent.

Advantages and Limitations

As with some flow monitors using pressure differential techniques, one advantage of thermal flow systems is their ability to produce measurements from the same "equal-area" sampling configuration required by EPA Reference Method 2. Because of this ability, if the flow profile varies significantly from one load or condition to another, thermal flow sensors may provide accurate results relative to EPA Method 2. As with pressure differential probes, however, build-up and corrosion can be a serious problem at some locations. Thermal flow monitors typically function better than other types of flow monitors under very low flow conditions (less than 10 fps); however, they should not be used after wet FGD systems or otherwise where condensation might occur.

OPACITY MONITORS

The degree to which transmitted light is obscured by particulate matter in the flue gas is the basis for measuring opacity.

Transmissometers, which are used to monitor in-situ levels of opacity in exhaust stacks or ducts, operate by passing visible light through the exhaust gas and measuring the percent obscuration caused by particulate matter in the effluent. As the light travels through the effluent, some will be absorbed and/or scattered by particulate matter and will not reach the detector. The transmittance of light through the effluent is therefore reduced, allowing

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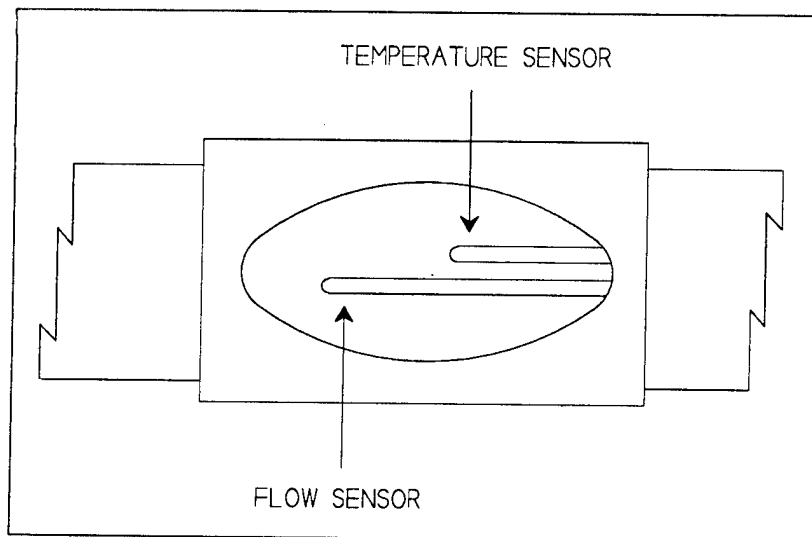
only a percentage of the original light beam to be measured. Opacity can be expressed as

$$\text{Opacity (\%)} = 100 - \text{Transmittance (\%)}$$

Therefore, if the effluent stream has a percent transmittance of 80%, the opacity of the effluent is 20%.

Figure 5-13

Thermal flow sensor.



There are two basic types of transmissometers: single-pass and double-pass systems. In a single-pass system, a lamp projects a beam of light across the stack to a detector, and the amount of light reaching the detector is sensed. Double-pass transmissometers are designed so that both the light source and the detector are contained in one unit, the transceiver. The light beam is projected across the stack in a manner similar to the single-pass systems, but the light beam is then reflected back through the effluent to the detector (hence the term, double pass). In some cases, the double-pass system's design enables the user to perform certain calibration checks more easily than does the single-pass system's design. Single-pass transmissometers are, however, typically less expensive than double-pass systems.

Both single- and double-pass transmissometers use an air purge system at the transmissometer/stack (or duct) interface to prevent particulate or moisture from collecting on the optics and causing erroneously high readings. Figure 5-14 illustrates the typical components found in a double-pass transmissometer.

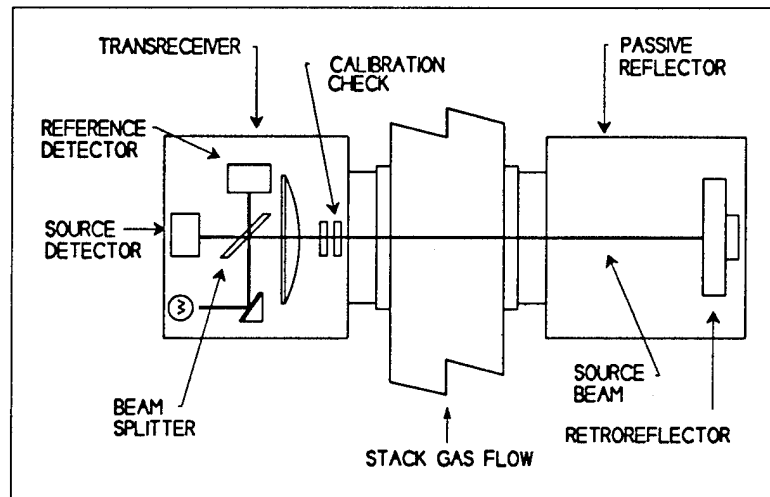
EPA's Performance Specification 1 (Appendix B, 40 CFR Part 60) defines minimum design and operation criteria for opacity monitors, and establishes a consistent mechanism by which opacity monitors can be evaluated and approved for use as specified in applicable regulations. It is implicit in opacity regulations that the measurement path length be equivalent to that of the stack exit diameter. However, since actual path lengths rarely correspond to stack outlet dimensions, most commercially available systems include an electronic ratio circuitry that provides a path length correction of apparent opacity to that value which would be measured at the stack exit. This correction factor is a frequent source of error, and the value used should be carefully checked upon delivery of the instrument.

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Single-pass and double-pass opacity monitors have been commercially available and used by utilities for more than 15 years. The underlying technology is mature, and only incremental advances have been made in recent years. Scattered light transmissometers, the other major opacity monitoring technology, are not currently used in the United States. A brief overview of these technologies is presented in the following paragraphs, along with a short discussion of recent technological advances in single-pass and double-pass monitors.

Figure 5-14
Typical double-pass transmissometer.



Commercially Available Equipment

At least two single-pass opacity monitors and at least eight double-pass opacity monitors are presently available. All of these monitors are suitable for complying with 40 CFR Part 75.

Recent Technological Advances

Some improvements have been incorporated into the design and construction of both single-pass and double-pass opacity monitors. Improved system controllers (microprocessor-based) are being installed in both exposed and protected environments. These controllers can provide improved automatic calibration and diagnostic procedures in order to check alignments, light source quality, optics, and a variety of other performance- or maintenance-related variables. Other advances include the isolation of all movable parts from the effluent gas, alarms to detect excessive buildup of particulate matter on filters, improved control cables that reduce interference, easily replaceable electronic components, and improved lamps with life expectancies from 3 to 10 years. One improvement in single-pass opacity monitoring technology is the use of fiber optic cables (passed around the outside of the stack or

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Double-pass transmissometers are more expensive, but also more reliable, than single-pass monitors.

Units affected by Part 75 must determine moisture so that SO₂ emissions can be reported in lb/hr.

Direct moisture measurements are made using NDIR and polarographic-based monitors.

Indirect moisture determinations are made on gases before and after moisture removal.

Moisture content can be determined using direct and indirect methods - Indirect methods are probably more reliable and accurate.

duct) to connect the transmitter and receiver, thereby allowing for zero and calibration checks while flue gas is in the stack.

Advantages and Limitations

Double-pass opacity monitors are generally more expensive than single-pass monitors; however, they also are historically more reliable and easier to calibrate. Certain relatively new design features on the single-pass units have reduced this advantage in some cases. Both types of monitors have improved on-stack component reliability, enclosures that are more waterproof and corrosion-resistant, and in many systems, automatic optical protection during air purge failures.

MOISTURE MONITORS

Although commercially available continuous moisture monitoring equipment has been used for many years in various industrial process and emission monitoring applications, before the advent of 40 CFR Part 75 regulations electric utilities had little need for moisture monitors. Part 75 regulations, however, require utilities to install moisture monitors for use with combined SO₂-flow extractive CEM systems so that SO₂ can be calculated in lb/hr. The following paragraphs provide an overview of moisture monitoring technologies and a discussion of the advantages and shortcomings of commercially available equipment.

Principle of Operation

Two approaches can be used for determining flue gas moisture content: (1) direct measurements or (2) calculation of moisture from other measurements made on wet and dry bases (i.e., indirect moisture determination). Monitors based on two analytical principles - NDIR and polarography - are available for direct determination of moisture. NDIR moisture monitors and polarographic moisture monitors operate on the same basic principles as NDIR and polarographic pollutant monitors.

Indirect moisture methods first measure the concentration of a gaseous compound in the sample gas on a wet basis and then on a dry basis; the percent difference in concentration between the wet and dry measurements is used to calculate gas moisture content. For example, flue gas O₂ content is determined on a wet basis (e.g., using a ZrO₂ analyzer) before the gas is passed through a moisture removal system; after moisture removal, flue gas O₂ content is measured on a dry basis, and the moisture content of the sample gas is calculated.

Commercially Available Equipment

At least six different NDIR moisture monitors and at least one polarographic moisture monitor are commercially available for direct determination of moisture. Several vendors offer monitoring equipment for indirect moisture determination. For a typical extractive system (i.e., a system that monitors SO₂, NO_x, and O₂ on a dry basis), only one additional monitor must be added to the system in order to determine moisture content.

Advantages and Limitations

Of the two approaches for determining moisture, the indirect approach is probably the more convenient (when using an extractive CEM system), reliable, and accurate method for most CEM systems. Depending on the type of CEM system, however, the costs to purchase and maintain this system could be relatively high.

NDIR moisture monitors can be sensitive to vibration; however, as with other NDIR monitors, solid-state detectors or microflow sensors will mini-

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mize vibration. Furthermore, NDIR monitor optics are sensitive to the corrosive properties of the sample gas as well as condensation. The sample gas, sample cell, and optical surfaces should be heated to a constant temperature, ensuring that the IR spectrum does not change and that no condensation is present. Polarographic analyzers are not as susceptible to vibration problems. The fuel cells do have a relatively short life span and, consequently, additional maintenance is usually required.

EMERGING TECHNOLOGIES

Several new monitoring technologies have emerged in the past several years. Fourier transform infrared (FTIR) analyzers, tunable diode laser infrared (TDIR) spectrometers, and mass spectrometers are among the developmental instruments available for monitoring flue gas constituents. New developments in flow monitoring technologies include infrared flow monitors, acoustic flow monitors, and fan efficiency devices. Scattered light transmissometers and LIDAR (Light Detecting And Ranging) represent two new techniques for monitoring opacity. These technologies are discussed in the following sections.

Emerging Gas Monitoring Technologies**Fourier Transform Infrared Analyzers**

Developmental gas monitoring technologies include FTIR analyzers, TDIR spectrometers, and mass spectrometers.

FTIR analyzers are currently undergoing preliminary evaluations for use in CEM systems by at least one utility with several FTIR vendors participating. FTIR analyzers operate on the general principle of spectrophotometric analysis. The spectrophotometer produces an IR spectrum consisting of a wide range of absorption wavelengths enabling a single instrument to monitor up to eight gases simultaneously during each reading cycle. The FTIR monitor uses an interferometer as an optical discriminator to scan quickly for compound-specific IR absorption wavelengths. The interferometer contains a stationary mirror and a movable mirror, both of which are at an equal distance from the beam splitter when measurements begin. As the movable mirror tracks away from the beam splitter at a constant velocity, it passes through positions where the beam of light from the IR source is partially reflected to the stationary mirror at a particular position and relayed to the tracking mirror at another particular position. As the beams reflect and return to the beam splitter, they interfere. The light is then partially reflected and partially transmitted once more. The resulting interference causes the intensity of the individual beams passing to the detector to vary depending on the difference of the path of the beams. The resultant interferogram provides all the data necessary to create an infrared spectrum. By applying the Fourier transform equation, the readings are changed from frequency to intensity, which corresponds to individual gas concentrations within the sample gas.

FTIR-based extractive CEM systems for measuring SO₂, NO₂, NO, CO₂, CO, CH₄, and other gases are available; however, these systems have not been subjected to any long-term field studies or field QA/QC programs. In general, these FTIR systems include a (1) probe constructed of materials suited to the effluent conditions; (2) heat-traced sample line; (3) conditioning unit, including filters; (4) condenser unit; and (5) microprocessor-based control unit.

Moisture and particulate matter are major interferences for these monitors that the manufacturers of these systems are still trying to eliminate. The monitors can be used downstream of a conditioning system that removes particulate matter and water vapor, but even after a conditioning system, some compensation for moisture and particulate matter interference may be required.

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Tunable Diode Laser Infrared Spectrometers

TDIR spectrometers use second-derivative spectroscopic analysis to determine the concentration of SO₂, NO₂, NO, CO₂, CH₄, H₂O, NH₃, HCl, HF, and other gases. An IR diode laser is used as the light source. The laser is coarsely calibrated by regulating its operating temperature, and fine adjustment is achieved by changing the current applied to the laser. A beam splitter is used to deflect a segment of the laser light through a reference gas cell and detector, providing the baseline measurement. The remainder of the laser light advances through a sample cell and is reflected back by a retroreflector to an analytic detector. The difference between the baseline signal and the analytical signal is directly proportional to the parameter concentration. As many as four diodes can operate at one time, enabling the system to monitor four different parameters in the gas stream simultaneously. The diodes can be replaced to operate in compound-specific spectral ranges. As with FTIR monitors, however, more information regarding long-term accuracy and reliability is needed. Current applications cited for the TDIR technology include limited stack emission monitoring, measurement of atmospheric pollutants over extended path lengths, and measurement of methane emissions from landfills.

Mass Spectrometers

Mass spectrometers measure the mass spectrum of ions created when a molecule is fragmented during ionization. These ions are indicative for that specific molecule and have the same collective mass-to-charge ratio as the molecule that was ionized. Ionization is accomplished in the monitor's vacuum chamber or ionizer by bombarding the molecule with electrons. The monitor selectively filters each ion according to its mass-to-charge ratio. Filtering takes place in a magnetic field using a quadrupole magnet (a cylinder containing four rods with an electrical potential of a specific strength and frequency applied to opposite pairs of rods) that allows only the desired ions to pass through the electrical field to the detector.

The detector constructs a mass spectrum that provides the necessary information to produce component concentration data. The mass spectrum of a sample is actually the total of the individual components' spectra. Therefore, if several components exist in the sample, the monitor subtracts the interfering component's ion spectra from the total to determine the desired component concentration.

To analyze for a specific compound, "analysis" ions must be selected on a case-by-case basis (before installing the system) from the total spectra of the effluent, using the accompanying system software. Generally, the software produces both relative intensities and component concentrations for the effluent simultaneously. The most intense fragmented ions corresponding to the particular component of interest are identified and analyzed. These various analysis ions are then surveyed for relative interferences. Once the analysis ions are chosen, the quadrupole magnet is programmed correspondingly.

Several mass spectrometers are installed on non-utility processes. These systems include process-specific software for data systems. Industrial tests have shown the monitor to be durable and highly accurate, even at extremely low concentrations; no mass spectrometers, however, have been installed and operated at utility locations.

In-situ Spectroscopic Analyzers

Another new analyzer system entering the U.S. market from Sweden uses a xenon light source that generates IR, visible, and UV light waves. The monitors operate using single-pass in-situ techniques with a transmitter and receiver on opposing sides of the stack or duct. The light waves pass through the effluent to a parabolic reflector in the receiver. From the reflec-

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tor, the light waves are passed through a fiberoptic cable to a spectrometer. To date, approximately 25 of these systems have been sold to utilities in the United States.

Because of the wide range of light waves passed through the effluent, this system may be used to monitor many different compounds in the future. Currently, utilities are installing these systems to monitor SO₂, NO_x, CO₂, CO, H₂O, and opacity.

Recent developments in flow monitoring technology include IR and acoustic flow monitors, and fan efficiency devices.

Emerging Flow Monitoring Technologies

Within the past 2 years, vendors of ultrasonic, differential pressure, and thermal flow monitors have been very active in demonstration programs performed by EPA and various utilities. To date, these monitors have been considered the only three realistic technologies available. Several other flow monitoring technologies are beginning to surface in the CEM system market, including (1) infrared flow monitors, (2) acoustic flow monitors, and (3) fan efficiency devices. Although these monitors are briefly described below, it should be noted that limited data are currently available regarding their accuracy and long-term reliability, and more field testing at utilities should be performed before a thorough assessment can be made.

Infrared Flow Monitors

The spectrographic velocimeter (see Figure 5-15) measures gas flow rate using refraction of 1300 nm IR light. This wavelength is unaffected by water, pollutants, or other interferences. The light is projected off mirrors and through a port into the stack. As the light passes through the stack gases, bending occurs due to the different densities of the flowing gases. Light, affected by an average of all the "densities" across the stack, is returned to the transparent diffractionary grating device, which functions as a slit. The slit allows the amplification and neutralization (no light) caused by the bending of the light through the stack to be shown in a shadow graph. The shadow graph (light and dark images) will move at the same speed as that of the exhaust gases in the stack.

Only one manufacturer is known to produce this particular type of monitor. The technology has existed for years, but only recently has the equipment been modified and accepted as a viable method for measuring gas flow. The system has no moving parts, electronic circuit boards, or critical optics located on the stack, and no electrical signal is produced at the stack. The light source is located at a remote unit; the light signal is transmitted to the stack or duct monitoring location via fiber optic cables, and the shadow graph is transmitted to the remote location (also by fiber optic cables), where the graph is read by a digital reader.

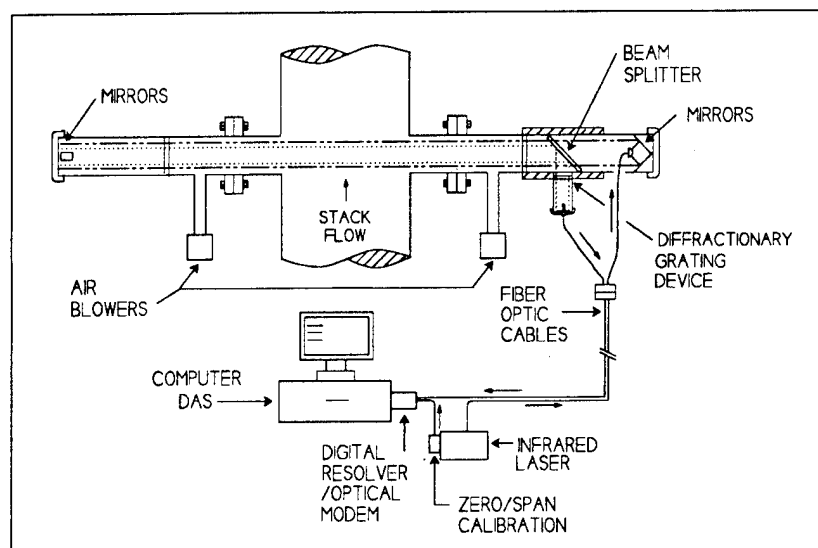
Acoustic Flow Monitors

Acoustic techniques have been used for years by meteorologists to measure wind speeds and directions (sonars). Acoustic flow monitors use audible sound bursts (as opposed to ultrasonic bursts) to measure gas velocity and employ equipment analogous to the ultrasonic flow monitors. Sufficient data are not available to determine if acoustic technologies have any advantages or disadvantages relative to ultrasonic monitors. With audible sound, however, the accuracy and reliability of the instruments when traversing larger ducts or adjusting for interferences may be significantly different relative to ultrasonic monitors.

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Figure 5-15
Infrared flow monitor.



Fan Efficiency Devices

At least one company has a flow monitoring system that measures induced draft (ID) fan inlet and fan outlet gas temperatures, in conjunction with fan horsepower, to determine exhaust gas flow rates at the ID fan locations. Volumetric flow is calculated by a microprocessor included in the system, using the temperature and horsepower measurements and design data for the fan. Two potential advantages to this approach are that (1) all three measurements required to determine flow can be obtained with a high degree of accuracy, and (2) duct configurations and the presence of turbulent flow should not affect the accuracy. However, one monitor is required for each ID fan (which may result in high capital and maintenance costs), and no long-term performance data are currently available.

Emerging Technologies for Opacity Monitors

Scattered Light Monitors

Emerging opacity measurements include scattered light monitoring and remote sensing, but both techniques are limited for current applications.

One manufacturer offers an opacity monitor based on the principle of scattered light measurement, which is extremely sensitive, especially for low particle concentrations. These types of transmissometers are not currently used in the United States, however, and in order to perform calibrations in accordance with EPA procedures, the scattered light monitor configurations would probably have to be modified. Light from a transmitter mounted at a specified angle is directed into the effluent stream. Although the effluent particles absorb a portion of the light energy, some of the light is also reflected and detected by a sensor. The higher the concentration of particles in the effluent stream, the greater the intensity of scattered (reflected) light. The amount of scattered light detected at the sensor is then compared with the intensity of the light emitted to determine the particle density. Note that the relationship between scattered light and concentration of particles does not always apply, especially at high opacities. Furthermore, while the reflector and detector for this type of monitor are installed side-by-side (the light does not traverse the stack or duct), simplifying installation requirements, the overall representativeness of the data collected at certain locations would be questionable.

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EPRI Licensed Material**Remote Sensing Devices**

In regard to remote sensing devices and new technology in opacity monitoring, LIDAR is a rather novel technique for measuring out-of-stack opacity. LIDAR operates on a principle similar to radar. Development of LIDAR measurement devices has progressed along two different system concepts. One device allows remote sensing of out-of-stack opacity, which is of primary interest to regulatory agencies and has been approved by EPA as an alternative to EPA Method 9 for opacity compliance measurements. The other device measures flue gas opacity inside the stack (in-situ) and corrects the opacity reading to an out-of-stack value. Both systems are based on detecting reflectance or backscatter of a projected light beam from a particulate-laden effluent. The light source usually is generated by a laser, and the intensity depends on the type of application. Reflected light is detected by a high sensitivity photocell, which must be properly aligned to minimize background light interferences. LIDAR is currently limited in use by its cost and operational limitations and, as a remote sensor, is almost exclusively limited to EPA enforcement divisions in compliance assessment activities.

DATA ACQUISITION SYSTEMS

Electronic data manipulation techniques are evolving rapidly, but Part 75 recordkeeping requirements will continue to challenge DAS technology.

Historically, the DAS has been one of the most problematic components of CEM systems. Major advances have been made in recent years in all aspects of electronic data processing, storage, and transmission, and such advances are expected to continue in the years ahead. Despite these advances, the problems associated with CEM system data systems are anticipated to increase, not decrease, in the years ahead as utility and regulatory agency of emission monitoring data attempt to take maximum advantage of electronic data processing, storage, and transmission technologies. EPA and several vendors are just beginning to perform beta-tests on EPA's software certification package and most vendors have just recently (while some have not yet) released "complete" commercial versions of their DAS software.

Functional Requirements of CEM System Data Acquisition Systems

DASs must perform data storage, calculations, and report generation.

Certain functional capabilities of DASs necessary to meet the requirements of 40 CFR Part 75 are summarized in the following paragraphs. DAS design should provide flexibility and the ability to expand.

Data Storage, Recordkeeping, and Transmittal

Part 75 requires DASs to provide a continuous and permanent record of all CEM system emission data, QA/QC audit results, and required process information. The emission measurements and information must be stored in a manner that facilitates transmittal as an ASCII flat file via personal computer disk or other electronic media (such as a modem).

Each DAS must be able to store data in accordance with the recordkeeping requirements stated in Subpart F of 40 CFR Part 75 and EPA's Electronic Data Reporting Procedures (Version 1.1). The system must be capable of maintaining these records (measurements, reports, and other required information) in a form suitable for inspection, at the source, for a period of 3 years. The records must contain unadjusted emission data, emission data adjusted for bias (when applicable), bias adjustment factor(s) (when applicable), emission data generated by missing data substitution procedures (when applicable), calibration data, and numerous other values. Records must be maintained in a flagged format.

A wide variety of DASs are currently offered by vendors, and most provide for data storage on a short-term basis (2 to 30 days) using a programmable logic controller (PLC); on a long-term basis (1 to 5 years) using a large PC; or on a permanent basis using tape drives. The DAS should provide an automatic method of back-up data storage. System design should also safeguard

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against unauthorized entry, tampering, power loss, and data loss due to lightning, static electricity, and other natural causes.

Calculations

The DAS must perform the calculations and conversions summarized in Appendix B (*Part 75 Data Conversion Procedures*) to this Guidelines Manual. Certain types of information (e.g., conversion factors, fuel F-factors, calibration gas values, flow monitor correction factors) must be input manually and updated periodically.

The DAS must record and calculate

- SO₂ emissions in ppm and lb/hr,
- NO_x emissions in lb/MBtu,
- volumetric flow in fps and scfh, and
- CO₂ emissions in lb/day.

All calculations associated with calculations, the procedures for missing data substitution, QA/QC, and bias adjustment must also be performed by the DAS.

Report Generation

The DAS must generate complete reports, in accordance with the content and format requirements of Part 75, for submittal to the applicable state or federal agency; the DAS should also be capable of generating any additional reports required by other applicable regulations. Examples of the required Part 75 reports are: (1) quarterly emission data and quarterly, semiannual, and annual QA/QC test result reports and (2) certification and recertification test reports. Some DASs can provide supplemental reports to assist corporate and plant personnel with boiler and CEM operations.

Each DAS should be capable of generating all required reports automatically with minimal editing by the CEM system operator and should also accommodate manual report production. Report generation should not interfere with ongoing CEM system operations.

System Status Tracking

Each DAS should include an alarm system to alert personnel when problems develop with the CEM system sampling and analysis components. Available alarm systems vary significantly in complexity, from systems that display a few simple messages on the computer screen to complex systems that deliver voice messages via telephone. During out-of-control or out-of-service periods, most DASs provide reason and comment codes that can assist the CEM system operator flagging the data. Most systems also provide some diagnostic capabilities, and some systems are capable of performing trend analyses. By tracking selected input parameters for various CEM system components, the CEM system operator may be alerted to possible maintenance requirements.

Incorporation of Process Data

Incorporating process data with emission monitoring data is a DAS function required by Part 75. For example, unit operating load data are needed for the missing flow and NO_x data substitution procedures. Most DASs being supplied by vendors to meet Part 75 have multi-tasking capabilities that facilitate automatic receipt and filing of process data without interrupting CEM system data logging operations. Most systems also readily accept additional process or supplemental data manually without interfering with other DAS functions. Such data can then be incorporated into reports or used for calcu-

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Operational control of the system is accomplished by a controller interfaced with a DAS.

lations (e.g., % monitor availability). PLCs are usually programmed to allow input and output of process information to and from the computer while recording CEM system responses, calculating emissions, and flagging data. However, programming to automatically receive process information from distributed control systems has not been extensively developed and tested. Both the hardware and software may require modification for each type of distributed control system used.

Functional Requirements of CEM System Controllers

Operational control and oversight of a CEM system are usually performed by an intelligent subsystem that is separate from, but interfaced with, the DAS. This subsystem is commonly referred to as the CEM system controller or CEM system control unit. The functions and functional requirements of CEM system controllers, as distinguished from those of the DAS, are summarized in the following sections. Controllers have been integral subsystems of CEM systems for many years, and thus are relatively mature technologies, having benefited in recent years from advances in microprocessor technology.

CEM System Operational Control

Many systems include PLCs or data loggers to control and monitor the operations of several analyzers and other CEM system components. Standard or optional features include monitor sequence control, blowback or back-purge functions, and sample conditioning diagnostics.

CEM System Calibration Control

Functions of a microprocessor-based controller typically include calibration control. The controller provides automatic calibration of the individual analyzers, including zero and span calibration error checks. Microprocessor-based systems usually include an enhanced alarm system to alert personnel to analyzer malfunctions and other abnormal conditions.

Data loggers are typically used to interface DASs with CEM system controllers.

Data Acquisition System Interface

Data loggers, a standard component of most CEM system controllers, are used for short-term data storage, emission calculations, and report generation. Other controllers convert signals from analog to digital form and use the computer for all data storage, calculations, and reporting.

Most systems use RS 232/422 serial data channels to interface the DAS computer with the CEM system controller. For some systems, however, interfacing is accomplished by using a modem; in this case, several considerations should be addressed. The best (and also the most expensive) method of transmitting data via modems requires using leased telephone lines. Leased telephone lines allow extremely rapid and direct interface between the two DAS components. These lines are subject to minimal noise or interference, and consequently, few transmission errors occur. Depending on the quality of the telephone lines available in a specific area, regular telephone lines may be adequate for data transmission; however, testing these lines at several transmission (baud) rates before installing a modem is recommended. It is important to note that, if many transmission errors occur, the amount of data ultimately transmitted by a high-speed modem may be less than the amount transmitted by a low-speed modem. Even though high-speed modems transmit larger amounts of data at one time, frequent transmission errors will result in a higher frequency of retransmissions.

Data Management Software

A variety of data base software is commercially available for managing CEM system data. Multi-tasking programs developed using OS2, ORIX, BASIC, Pascal, FORTRAN, ADA, UNIX, and secondary software packages such as

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DBase IV, Lotus, Excel, and Alpha Four provide a means of managing large data bases.

Many DASs supplied by CEM system vendors incorporate proprietary software or databases or simply are not configured to export data for use at other terminals or workstations. User access is therefore typically limited to the hardware associated with the CEM installation, and therefore to the data at a single unit or plant. To avoid this limitation, utilities should specify that the system software support the export of new or revised data on a 24-hour basis. The file structure should be standard, such as standard query language (SQL) or Oracle (the utilities data manager), so that the data can be imported easily into another software package. File format (order, rows, and columns) must also be specified; EPRI has developed the CEM Reporting Workstation (CEMRW) to read CEM data from a standard data file having the format shown in Attachment A to Appendix F of this Guidelines Manual.

Several commercial options are available for interfacing distributed control systems with DASs.

Integration of DASs and Distributed Control Systems

Westinghouse, Leeds & Northrop, GE Fanuc Automation, and Honeywell provide distributed control systems (DCS) for power plants. These systems include complete software packages for monitoring and controlling boilers and other power plant operations. The systems are available in various configurations, including some that will interface with a control room main-frame computer.

Some DCS system suppliers indicate that the data acquisition, processing, and storage functions of a DAS can be easily integrated into existing DCSs. Conceptually, integration with the CEM system is an attractive alternative to a self-standing DAS. Advantages of this alternative include (1) direct access to process data; (2) optimum utilization of existing on-line and backup computer data storage capacity; (3) convenient, single-point access to boiler and CEM system data; and possibly (4) facilitation of CEM system data reporting.

Although there are potential advantages, the difficulties associated with integrating CEM system data acquisition, processing, storage, and reporting into a DCS should not be underestimated. As noted previously, CEM system data recording and reporting must be performed in accordance with certain regulatory requirements that may not be met by existing DCS software. Modifying existing DCS software to meet these regulatory requirements may not be possible within the required time frames, and the cost of such modifications could be significant. Furthermore, self-standing CEM system data systems historically have been plagued by programming problems (bugs); the possibility of such bugs occurring in DCS that are adapted for CEM system data handling should not be discounted. Bugs in the CEM system data management software may interfere with overall DCS operations, causing disruption of plant operations. Because the DCS is subject to many changes in inputs, outputs, and screen designs, it must also be properly secured to prevent changes to the CEM system's integrated software, which would require recertification of the system.

CEM System Software Available for Personal Computer Systems

Most CEM system software packages are designed for use with IBM or IBM-compatible PC systems. Many CEM system manufacturers offer software packages tailored to the specific needs of the customers. Although some software is interchangeable, most is designed to meet the needs of a particular system. Some software includes functions for data acquisition, data editing and analysis, report writing, facility-specific reporting, and operator interface.

Many companies offering a complete data acquisition software package combine these functions. Most operating systems are multi-tasking, thereby

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allowing continuous data collection even during report generation. Also, most systems have multi-processing capabilities, which ensure that system operations continue even when a hardware component fails.

System Hardware**Controllers**

PLCs control functions, data manipulations, and monitoring for analyzer components of CEM systems.

PLCs are microprocessor-based subsystems that provide control functions, data manipulation, and monitoring for the various analyzers. They perform calibration checks, self-diagnostics, sequence control, and alarming to alert personnel to routine maintenance needs. PLCs accept a broad range of input signals (analog, digital, thermocouple, and contact closures) from the analyzers and other CEM system components. They can provide serial or parallel outputs using analog or digital signals depending on requirements of the recording or display device, such as PCs, strip chart recorders, printers, or mainframe computers. Many units provide an onboard display and keypad. The units with onboard displays offer a variety of data displays. A data backup system is a typical option for preserving data if the DAS computer malfunctions.

Computers

386 or 486 IBM-compatible PCs are typically used as the foundation for DASs.

The computers used in the DASs are typically 386 or 486 IBM-compatible PCs, manufactured by IBM, Compaq, Austin, AST, Gateway, and others. Countless variations of each system are available to meet specific operating needs. A local area network (LAN) interface, such as TCP/IP should be specified for the DAS. Such an interface will enable the DAS to electronically transmit data to the corporate or plant computer network. A modem or floppy disk interface may be substituted if a network is not established. Printers, color monitors, and modems are optional features; 4 to 8 megabytes of internal memory (RAM) are typically provided in conjunction with a 120-megabyte (or greater) hard drive for data storage. The more reliable 386 and 486 33-megahertz and 40-megahertz computers should provide ample speed for any software required to ensure compliance with Part 75.

Other Hardware and Software Considerations

Multi-tasking software and uninterruptable power supplies can help avoid data loss.

Additional hardware items may be required to maximize DAS flexibility and provide data backup. When selecting computer hardware, the CEM system operator should request that the computer have 8 (the maximum) expansion slots to accommodate future and anticipated modifications such as networking, additional modems, and other process interfaces. The operator should also ensure that data storage and backup procedures are adequate — options include additional data storage capabilities in the PLC, data storage on a mainframe computer, tape drive backups, and disk mirroring (two identical hard drives within the computer).

Multi-tasking software should be used on all DASs. Unlike DOS-based software, which processes one data file at a time, multi-tasking software can process several files simultaneously. Multi-tasking capability is clearly advantageous; however, loss of power to a multi-tasking DAS could result in loss of data from each file being processed. Thus, backup power supplies or uninterruptable power supplies (UPSs) should be considered for all DASs (a non-switching UPS is preferred) and possibly for the entire CEM system. Backing out of a multi-tasking program typically requires approximately 5 minutes and UPS (currently installed for plant operations or otherwise purchased with the CEM system) are available that can provide backup power to a DAS for time periods ranging from 5 minutes to 6 or 7 hours. Consequently, when an interruption in the primary power supply is detected for a DAS or other CEM components that are equipped with a UPS, the multi-tasking program and other components may continue operating until approximately 10 minutes of reserve power remain in the UPS or may immediately shut down, as desired.

Appendix D: CEM Instruments and Equipment; Analytical Principle by Manufacturer

*EPRI Licensed Material***APPENDIX J****CEM INSTRUMENTS AND EQUIPMENT:
ANALYTICAL PRINCIPLE BY MANUFACTURER**

The following information was compiled from a larger survey of vendors that currently provide CEM systems to the utility industry. The analytical principle for CEM instruments and/or equipment manufactured by vendors, as well as the equipment type, are shown. Descriptions of analytical principles vary due to differing levels of detail provided in vendor information.

Vendor Name and Address	Equipment Manufactured	Analytical Principle	Equipment Type
ABB Environmental 9111 Cross Park Drive, Bldg. C P.O. Box 87 Knoxville, TN 37901 (800) 341-0460	SO ₂	Remote spectroscopy	Remote
	NO _x	Remote spectroscopy	Remote
	CO ₂	Remote spectroscopy	Remote
	CO	Remote spectroscopy	Remote
Advanced Pollution Instruments 8815 Production Drive San Diego, CA 92121-2219 (619) 578-2154	SO ₂	UV fluorescence	Extractive
	NO _x	Chemiluminescence	Extractive
Air Instruments & Measurements 13111 Brooks Drive, Suite D Baldwin Park, CA 91706 (818) 813-1466	SO ₂	NDIR, single-beam, double-pass	In-situ
	NO _x	NDIR, single-beam, double-pass	In-situ
	CO ₂	NDIR, single-beam, double-pass	In-situ
	CO	NDIR, single-beam, double-pass	In-situ
	H ₂ O	NDIR, single-beam, double-pass	In-situ
	Opacity	Single-pass transmissometer	In-situ
Air Monitor 1050 Hopper Avenue P.O. Box 6358 Santa Rosa, CA 95406 (800) 247-3569	Temperature	Thermocouple	In-situ
	Flow	Multipoint, self-averaging pitot tube flow sensor	In-situ
AMETEK, Inc. 455 Corp. Boulevard Pencader Center Newark, DE 19702 (800) 222-6789	SO ₂	UV, split-beam, photometric differential absorption	Extractive
Anarad 534 E. Ortega Street Santa Barbara, CA 93103 (800) 963-6583	SO ₂	NDUV	Extractive
	SO ₂	FTIR	Extractive
	NO _x	Chemiluminescence	Extractive
	NO _x	FTIR	Extractive

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Vendor Name and Address	Equipment Manufactured	Analytical Principle	Equipment Type
Anarad (continued)	NO _x	NDUV	Extractive
	CO ₂	NDIR	Extractive
	CO ₂	FTIR	Extractive
	O ₂	Electrocatalytic (zirconium oxide)	Extractive
	O ₂	FTIR	Extractive
	CO	NDIR	Extractive
	CO	FTIR	Extractive
	H ₂ O	NDIR	Extractive
	H ₂ O	FTIR	Extractive
Bodenseewerk* (Perkin Elmer GmbH) P.O. Box 101164 D-7770 Überlingen Federal Republic of Germany 07532-801-100	SO ₂	NDIR, single-beam, dual wavelength	Extractive
	NO _x	Chemiluminescence	Extractive
	CO ₂	NDIR, single-beam, dual wavelength	Extractive
	CO	Gas filter correlation	Extractive
	H ₂ O	NDIR, single-beam, dual wavelength	Extractive
* Distributed by: Altech Systems Corp. 11969 Challenger Court Moorpark, CA 93201 (805) 529-9955			
Columbia Scientific Inst. 11950 Jollyville Road P.O. Box 203190 Austin, TX 78720 (512) 258-5191	SO ₂	Flame photometry	Extractive/Ambient
	SO ₂	UV fluorescence	Extractive/Ambient
	NO _x	Chemiluminescence	Extractive/Ambient
DASIBI Environmental Corp. 515 W. Colorado Street Glendale, CA 91204	SO ₂	UV fluorescence	Ambient
	NO _x	Chemiluminescence	Ambient
	CO	IR gas filter correlation	Ambient
DATATEST 6850 Hibbs Lane Levittown, PA 19057 (215) 943-0668	SO ₂	NDIR	Extractive
	NO _x	Chemiluminescence	Extractive
	NO _x	NDIR	Extractive
	CO ₂	NDIR	Extractive
	O ₂	Electrocatalytic (zirconium oxide)	In-situ/Extractive
	CO	NDIR	Extractive
	Temperature	Type R thermocouple	In-situ
	Opacity	Single-pass transmissometer	In-situ
	Opacity	Dual-pass transmissometer	In-situ
Dieterich Standard Corp. Allen T. Shepard Co. P.O. Box 1451 Greensboro, NC 27402 (919) 292-0261	Temperature	Resistive temperature device/Thermowells	In-situ
	Flow	Annubar sensor	In-situ
Dupont Company* Instruments Systems Concord Plaza, Quillen Building Wilmington, DE 19898 (302) 772-5481	SO ₂	UV, split-beam photometry	Extractive
	NO _x	UV, split-beam photometry	Extractive
* Distributed by: AMETEK, Inc. 455 Corp. Boulevard Pencader Center Newark, DE 19702 (800) 222-6789			

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Vendor Name and Address	Equipment Manufactured	Analytical Principle	Equipment Type
EEMC/EMRC 3925 Placita de la Escarpa Tucson, AZ 85725 (602) 290-8965	Temperature Flow	Type K thermocouple S-type pitot tube	In-situ In-situ
ENVIROPLAN 59 Main Street West Orange, NJ 07052 (201) 994-2300	O ₂ Dilution probes Opacity	Electrocatalytic (zirconium oxide) Dual-pass transmissometer	In-situ Dilution In-situ
EPM-Environmental, Inc. 610 South Albert Street P.O. Box 11 Mount Prospect, IL 60056 (708) 255-4494	Dilution probes		Dilution
Erwin Sick - GmbH* OPTIK-ELEKTRONIK Environmental Systems Division Nimburger Strasse D-7801, Reute Federal Republic of Germany 07641-4690	SO ₂ NO _x Flow Opacity Opacity	UV spectroscopy UV spectroscopy Ultrasonic Dual-pass transmissometer Scattered light method	In-situ In-situ In-situ In-situ In-situ
* Distributed by: ESI - US, Inc. 2214 Morse Avenue Scotch Plain, NJ 07076 (201) 654-1292			
Exergetic Systems, Inc. P.O. Box 3271 Livermore, CA 94550 (510) 449-8100	SO ₂ NO _x CO ₂ CO H ₂ O Temperature Opacity	IR spectroscopy IR spectroscopy IR spectroscopy IR spectroscopy IR spectroscopy Resistive temperature device Single-pass transmissometer	In-situ In-situ In-situ In-situ In-situ In-situ In-situ
Fluid Components, Inc. 1755-T LaCosta Meadows Drive San Marcos, CA 92069 (619) 744-6950	Flow Flow Flow	Thermal dispersion, single-point mass Thermal dispersion, multipoint mass Thermal dispersion, air mass	In-situ In-situ In-situ
Fluid Data 1844 Landsdowne Avenue Merrick, NY 11566 (516) 379-0098	SO ₂ CO ₂ CO ₂ O ₂ CO CO H ₂ O	NDIR IR interference filter correlation NDIR Paramagnetic (magnetopneumatic) IR interference filter correlation NDIR Electrolytic cell	Extractive Extractive Extractive Extractive Extractive Extractive Extractive
Horiba Instruments, Inc. 1021 Duryea Avenue Irvine, CA 92714 (714) 250-4811	SO ₂ SO ₂ NO _x NO _x CO ₂ O ₂ CO	NDUV NDIR NDIR Chemiluminescence NDIR Paramagnetic (magnetopneumatic) NDIR	Dilution/Ambient Dilution/Ambient Dilution/Ambient Dilution/Ambient Dilution/Ambient Dilution/Ambient Dilution/Ambient

Appendix J

EPRI Licensed Material

Vendor Name and Address	Equipment Manufactured	Analytical Principle	Equipment Type
Kurz Instruments 2411 Garden Road Monterey, CA 93940 (704) 847-9125	Temperature Flow	Resistive temperature device Thermal convective	In-situ In-situ
KVB, Inc. 9342 Jeronimo, Suite 101 Irvine, CA 92718 (714) 587-2300	SO ₂ NO _x	UV fluorescence Chemiluminescence	Extractive Extractive
Lear Siegler 1651 Phoenix Boulevard, Suite #6 Atlanta, GA 30349 (404) 991-9430	SO ₂ SO ₂ SO ₂ SO ₂ NO _x NO CO ₂ O ₂ CO CO H ₂ O Opacity	UV photometry UV photometry UV second-derivative spectroscopy UV fluorescence Chemiluminescence UV photometry NDIR Electrocatalytic (zirconium oxide) NDIR IR gas filter correlation NDIR Dual-pass transmissometer	In-situ Extractive In-situ Extractive Extractive In-situ In-situ In-situ In-situ Extractive In-situ In-situ
Milton Roy Process & Environmental Division 1238 W. Grove Avenue Orange, CA 92665-4134	SO ₂ NO _x CO ₂ O ₂ O ₂ O ₂ CO	NDIR Chemiluminescence NDIR NDIR Paramagnetic Electrocatalytic (zirconium oxide) NDIR	Extractive Extractive Extractive Extractive Extractive Extractive Extractive
Panametrics/PCI 221 Crescent Street Waltham, MA 02154-3497 (617) 899-2719	Flow	Ultrasonic	In-situ
Rosemount 1201 N. Main Street P.O. Box 901 Orville, OH 44667-0901 (216) 682-9010	SO ₂ SO ₂ SO ₂ NO _x CO ₂ CO ₂ O ₂ CO CO Opacity	UV pulsed fluorescence IR spectroscopy FTIR Chemiluminescence IR spectroscopy FTIR Paramagnetic IR spectroscopy FTIR Dual-pass transmissometer	Extractive Extractive Extractive Extractive Extractive Extractive Extractive Extractive Extractive In-situ
Scientific Engineering Inst., Inc. 1275 Kleppe Lane, Suite 14 Sparks, NV 89431 (702) 358-0937	Flow Temperature	Ultrasonic Acoustic pyrometer	In-situ In-situ
SERVOMEX 90 Kerry Place Norwood, MA 02062 (617) 769-7710	SO ₂ CO ₂ O ₂ O ₂ CO H ₂ O	NDIR IR gas filter correlation Paramagnetic (magnetodynamic) Electrocatalytic (zirconium oxide) IR gas filter correlation NDIR	Extractive Extractive Extractive Extractive Extractive Extractive

EPRI Licensed Material**CEM Equipment**

Vendor Name and Address	Equipment Manufactured	Analytical Principle	Equipment Type
Teledyne Analytical 16830 Chestnut Street P.O. Box 1580 City of Industry, CA 91749-1580 (808) 961-9221	SO ₂	UV photometry	Extractive
	NO _x	Chemiluminescence	Extractive
	CO ₂	NDIR photometry	Extractive
	O ₂	Electrochemical fuel cell	Extractive
	O ₂	Electrocatalytic (zirconium oxide)	Extractive
	CO	NDIR photometry	Extractive
	H ₂ O	NDIR photometry	Extractive
Teledyne Hastings - Raydist P.O. Box 1275 Hampton, VA 23661 (804) 723-6531	Temperature	Resistive temperature device	In-situ
	Flow	Resistive temperature device	In-situ
Thermo Environmental 8 West Forge Parkway Franklin, MA 02038 (508) 520-0430	SO ₂	UV pulsed fluorescence	Extractive/Ambient
	NO _x	Chemiluminescence	Extractive/Ambient
	CO ₂	IR gas filter correlation	Extractive/Ambient
	CO	IR gas filter correlation	Extractive/Ambient
	Opacity	Dual-pass transmissometer	In-situ
Thermox Division of AMETEK, Inc. 455 Corp. Boulevard Pencader Center Newark, DE 19702 (800) 222-6789	O ₂	Electrocatalytic (zirconium oxide)	In-situ
	CO	NDIR	Extractive
United Sciences 5310 N. Pioneer Road Gibsonia, PA 15044 (412) 443-8610	Flow	Ultrasonic	In-situ
	Opacity	Dual-pass transmissometer	In-situ
Western Research & Dev. 1313 44th Avenue, NE Calgary Alberta, Canada T2E 6L5 (800) 661-9298	SO ₂	UV spectroscopy	Extractive

Appendix E: Ambient Air Monitoring (Industry), Approved Methods as of December 1994

No. 178

AMBIENT AIR MONITORING (INDUSTRY)

141:1021

APPROVED METHODS AS OF DECEMBER 1994

<u>METHOD</u>	<u>DESIGNATION NUMBER*</u>	<u>FEDERAL REGISTER DATE**</u>
SO₂ Manual Methods		
Ref. method (pararosaniline)	(Appendix A)	4/22/83
Technicon I (pararosaniline)	EQS-0775-001	8/13/75
Technicon II (pararosaniline)	EQS-0775-002	8/13/75
SO₂ Analyzers		
API, Inc. 100	EQSA-0990-077	9/17/90
Asarco 500	EQSA-0877-024	11/26/79
Beckman 953	EQSA-0678-029	8/14/78
Bendix 8303	EQSA-1078-030	10/31/78
Columbia Scientific Industries 5700	EQSA-0494-095	4/20/94
Dasibi Model 4108	EQSA-1086-061	9/10/86
Environnement S.A. AF21M	EQSA-0292-084	2/14/92
Lear Siegler AM2020	EQSA-1280-049	1/30/81
Lear Siegler ML9850	EQSA-0193-092	2/3/93
Lear Siegler SM1000	EQSA-1275-005	1/4/80
Meloy SA185-2A	EQSA-1275-006	8/25/78
Meloy SA285E	EQSA-1078-032	10/31/78
Meloy SA700	EQSA-0580-046	5/13/80
Monitor Labs 8450	EQSA-0876-013	6/11/79
Monitor Labs 8850	EQSA-0779-039	7/30/79
Monitor Labs 8850S	EQSA-0390-075	2/14/90
Philips PW9700	EQSA-0876-011	8/12/76
Philips PW9755	EQSA-0676-010	6/3/77
Thermo Electron 43	EQSA-0276-009	5/16/80
Thermo Electron 43A	EQSA-0486-060	4/10/86
O₃ Analyzers		
API, Inc. 400	EQOA-0992-087	9/28/92
Beckman 950A	RFOA-0577-020	6/3/77
Bendix 8002	RFOA-0176-007	3/21/80
CSI 2000	RFOA-0279-036	2/20/79
Dasibi 1003-AH,-PC,-RS	EQOA-0577-019	6/3/77
Dasibi 1008-AH	EQOA-0383-056	3/10/83
Enviro-nics Series 300	EQOA-0990-078	9/18/90
Lear Siegler ML9810	EQSA-0193-091	2/3/93
McMillan 1100-1	RFOA-1076-014	6/13/77
McMillan 1100-2	RFOA-1076-015	6/13/77
McMillan 1100-3	RFOA-1076-016	6/13/77
Meloy OA325-2R	RFOA-1075-003	11/26/75
Meloy OA350-2R	RFOA-1075-004	11/26/75
Monitor Labs 8410E	RFOA-1176-017	12/8/76
Monitor Labs 8810	EQOA-0881-053	10/26/81
PCI Ozone Corp. LC-12	EQOA-0382-055	3/31/82
Philips PW9771	EQOA-0777-023	11/1/77
Thermo Electron 49	EQOA-0880-047	8/27/80
TSP Manual Method		
Reference method (high-volume)	(Appendix B)	4/22/83

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MONITORING AND REPORTING

No. 178

<u>METHOD</u>	<u>DESIGNATION NUMBER*</u>	<u>FEDERAL REGISTER DATE**</u>
PM₁₀ Manual Method		
Ref. method (gravimetric manual)	(Appendix J)	8/7/87
Wedding & Associates	RFPS-1087-062	10/6/87
Sierra-Anderson (or GMW) 1200	RFPS-1287-063	1/15/88
SA (or GMW) 321-B	RFPS-1287-064	1/15/88
SA (or GMW) 321-C	RFPS-1287-065	1/15/88
Oregon DEQ (medium-volume)	RFPS-0389-071	3/24/89
SA (or GMW) SA241, SA241M and G241, G241M	RFPS-0789-073	7/27/89
Rupprecht & Patashnick Partisol Model 2000 Air Sampler (gravimetric manual)	RFPS-0694-098	7/11/94
PM₁₀ Automated Method		
Andersen Instruments FH62I-N	EQPM-0990-076	9/18/90
Rupprecht & Patashnick TEOM 1400	EQPM-1090-079	10/29/90
Wedding & Associates (Beta Gauge)	EQPM-0391-081	3/5/91
NO₂ Manual Methods		
Sodium arsenite	EQN-1277-026	12/14/77
Sodium arsenite/Technicon II	EQN-1277-027	12/14/77
TGS-ANSA	EQN-1277-028	12/14/77
NO₂ Analyzers		
API, Inc 200	RFNA-0691-082	6/12/91
API, Inc 200A	RFNA-1194-099	12/2/94
Beckman 952A	RFNA-0179-034	2/7/79
Bendix 8101-B	RFNA-0479-038	5/7/79
Bendix/CE 8101-C	RFNA-0777-022	7/21/77
CSI 1600	RFNA-0977-025	9/16/77
Dasibi 2108	RFNA-1192-089	11/25/92
Lear Siegler ML9841	RFNA-1292-090	12/18/92
Meloy NA530R	RFNA-1078-031	2/9/79
Monitor Labs 8440E	RFNA-0677-021	6/4/81
Monitor Labs 8840	RFNA-0280-042	6/4/81
Monitor Labs 8841	RFNA-0991-083	9/19/91
Philips PW9762/02	RFNA-0879-040	9/4/79
Thermo Electron 14B/E	RFNA-0179-035	9/20/79
Thermo Electron 14D/E	RFNA-0279-037	2/20/79
Thermo Environmental 42	RFNA-1289-074	12/11/89
Pb Manual Methods		
Ref. method (hi-vol/AA spect.)	(Appendix G)	10/5/78
Hi-vol/AA spect. (alt. extr.)	EQL-0380-043	3/6/80
Hi-vol/Flameless AA (EMSL/EPA)	EQL-0380-044	3/6/80
Hi-vol/ICAP spect. (EMSL/EPA)	EQL-0380-045	3/6/80
Hi-vol/Wavelength disp. XRF	EQL-0581-052	6/4/81
Hi-vol/ICAP spect. (Montana)	EQL-0483-057	4/5/83
Hi-vol/Energy-disp. XRF	EQL-0783-058	6/28/83
Hi-vol/Flameless AA (Omaha)	EQL-0785-059	9/18/85
Hi-vol/ICAP spect. (Rhode Island)	EQL-0888-068	8/16/88
Hi-vol/ICAP spect. (NET, Inc.)	EQL-1188-069	11/7/88
Hi-vol/ICAP spect. (Silver Valley Labs)	EQL-1288-070	12/5/88
E-disp. X-ray fluor. spect. (NEA, Inc.)	EQL-0589-072	5/10/89
Hi-vol/ICAP spect. (New Hampshire)	EQL-1290-080	11/26/90

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AMBIENT AIR MONITORING (INDUSTRY)

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<u>METHOD</u>	<u>DESIGNATION NUMBER*</u>	<u>FEDERAL REGISTER DATE**</u>
Hi-vol/ICAP spect. (Kansas)	EQL-0592-085	5/15/92
Hi-vol/ICAP spect. (Pennsylvania)	EQL-0592-086	5/15/92
Hi-vol/ICAP spect. (Illinois)	EQL-1193-094	11/23/93
Thermo Jarrel Ash AtomScan 16/in- ductively coupled argon plasma optical emission spect. (West Virginia)	EQL-0694-096	6/7/94
CO Analyzers		
API, Inc. 300	RFCA-1093-093	10/29/93
Beckman 866	RFCA-0876-012	8/27/76
Bendix/CE 8501-5CA	RFCA-0276-008	2/18/76
Dasibi 3003	RFCA-0381-051	4/7/81
Dasibi 3008	RFCA-0488-067	4/12/88
Horiba AQM-10,-11,-12	RFCA-1278-033	12/14/78
Horiba APMA-300E/300SE	RFCA-1180-048	11/3/80
Lear Siegler ML 9830	RFCA-0992-088	9/28/92
LIRA 202S	RFCA-0177-018	1/31/77
MASS — CO 1 (Massachusetts)	RFCA-1280-050	12/11/80
Monitor Labs 8310	RFCA-0979-041	1/14/80
Monitor Labs 8830	RFCA-0388-066	3/7/88
Thermo Electron 48	RFCA-0981-054	9/23/81

*If method is a reference method, the source appendix to 40 CFR 50 is cited in ().

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